PUBLIC SERVICE COMMISSION OF WISCONSIN

STRATEGIC ENERGY ASSESSMENT DRAFT REPORT

ENERGY 2012

610 NORTH WHITNEY WAY
MADISON, WISCONSIN

DOCKET 5-ES-103
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TO THE READER

This is the fourth biennial draft Strategic Energy Assessment (SEA) issued by the Public Service Commission of Wisconsin (Commission), an independent state regulatory agency, whose authority and responsibilities include regulatory oversight over electric service in Wisconsin. The SEA provides a picture of past and future electric energy needs and sources of supply. It brings to light issues that may need to be addressed to ensure the availability and reliability of Wisconsin's electric energy supply.

While the Commission is required to prepare this technical document for comments by parties involved in the electric industry, the Commission also intends that the SEA be available to the general public having an interest in reliable, least-cost electric energy. To assist the general public, definitions of key terms used within the electric industry are included in the draft.

The Commission is required to hold a public hearing before issuing a final SEA. A copy of the notice providing information on the hearing is included with this mailing, and is available for review on the Commission's website (http://psc.wi.gov). The Commission must make an environmental assessment on the draft SEA before the final report is issued. It will be available on the Commission's website at least 30 days prior to the public hearings.

Questions regarding the process or the public hearing, or requests for additional copies of the draft SEA should be directed to Christine Swailes, (608) 266-8776. Questions from the media and the legislature may be directed to Linda Barth at (608) 266-9600.

Written comments and comments presented at the public hearing will be used to prepare the final SEA. The Commission encourages all interested persons to comment on the content of this report during the 90-day comment period, which began with the mailing of this draft SEA. Please address your written comments to:

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TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

STRATEGIC ENERGY ASSESSMENT DRAFT REPORT

2006-2012 ELECTRICITY ISSUES

Study Scope

The Public Service Commission of Wisconsin (Commission or PSC) is required to prepare a biennial Strategic Energy Assessment Report (SEA) that evaluates the adequacy and reliability of Wisconsin's current and future electrical supply.

The SEA intends to identify and describe:

- All large electric generating facilities for which an electric utility or merchant plant developer plans to commence construction within seven years.
- All high-voltage transmission lines for which an electric utility plans to commence construction within seven years.
- Any plans for assuring that there is an adequate ability to transfer electric power into or out of eastern Wisconsin, and the state as a whole, in a reliable manner.
- The projected demand for electric energy and the basis for determining the projected demand.
- Activities to discourage inefficient and excessive power use.
- Existing and planned generation facilities that use renewable energy sources.

The SEA is required by statute to assess:

- The adequacy and reliability of purchased generation capacity and energy to serve the needs of the public.
- The extent to which the regional bulk-power market is contributing to the adequacy and reliability of the state's electrical supply.
- The extent to which effective competition is contributing to a reliable, low-cost, and environmentally sound source of electricity for the public.
- Whether sufficient electric capacity and energy will be available to the public at a reasonable price.

The SEA must also consider the public interest in economic development, public health and safety, protection of the environment, and diversification of sources of energy supplies.

Study Methodology

Under statutory and administrative code requirements, every electricity provider and transmission provider must file historic and forecasted information. The draft SEA must be distributed, by July 1 of each even-numbered year, to interested parties for comments. Subsequent to hearings and receipt of written comments, the final SEA is issued. In addition, an Environmental Assessment, which includes a discussion of generic issues and environmental impacts, is issued in connection with the SEA.

This fourth SEA covers the years 2006 through 2012. This SEA has been assigned the Commission docket 05-ES-103. In September 2005, ten large Wisconsin-based investor-owned utilities, cooperatives, municipal electric companies, and other electricity and transmission providers submitted historic information regarding statewide demand, generation, out-of-state sales and purchases, transmission capacity, and energy efficiency efforts. In addition, these entities provided forecasted information through 2012.

Study Limitation

It is important to highlight that the SEA is an informational study that informs the public and stakeholders of relevant trends, facts and issues affecting the state's electric industry. The SEA is not a prescriptive report, meaning that the ideas, facts, projects, and policy changes contained in this report have not been approved for implementation or construction by the Commission. State law precludes such action, specifically Wis. Stat. § 196.491(3)(dm). Should a specific topic warrant further attention with the intent of Commission action, then the Commission must by law commence the appropriate formal proceeding.

Overview of Contents

The remainder of this report describes, illustrates and summarizes the information filed with the Commission in September, 2005, by public utilities serving Wisconsin and by other interested participants in February of this year. This summary information includes:

- Historic, current, and forecasted electricity markets, as reflected in the information provided by the industry participants and, where appropriate, supplemented by Commission staff.

- Wisconsin's transmission system, including the current operation of the system, expected changes, and challenges to the operation of the system.

- Descriptions of Wisconsin's energy future, with emphasis on the four assessments required by the statutes.

- Current and proposed efforts to conserve energy.

- The diversity of fuel used to generate the energy that is consumed and the effects of the entire electric system on public health, safety and the environment.

- Summarized rate and cost trends.

- Questions and summarized comments about the challenges facing Wisconsin's electric industry.

This summary information is provided to facilitate dialog between the Commission, public utilities, interested participants and the public. A public legislative-style hearing is expected to be held later this year. Any additional input, feedback and analysis received by the Commission regarding the questions and the data presented in this draft SEA, and on the Commission's Electronic Regulatory Filing (ERF) system database, will be summarized in the final SEA issued later in 2006.

EXECUTIVE SUMMARY

Demand and Supply of Electricity

The overall trend in demand growth is estimated to be approximately 2.0 percent per year through 2012.

Over 1,300 MW of new generation capacity became commercially available in Wisconsin in 2005.

Over the next five years, through 2010, over 3,000 MW of additional, new generation is expected to be brought into service.

The new generation will reduce Wisconsin's reliance on the currently congested transmission grid connections to Illinois and will maintain a robust planning reserve margin through 2012.

Significant progress has been made by electricity providers in meeting the 18 percent planning reserve margin requirement. Wisconsin will very likely have adequate supply resources in the 2005-2012 timeframe.

Generation ownership has changed. In 2005 the Commission approved the sale of the Kewaunee Nuclear Power Plant to Dominion Energy Kewaunee, a subsidiary of Dominion. Also, independent power producers have been active in developing wind projects in Wisconsin.

Transmission

Table A-02 contains a list of transmission line projects on which construction would begin before 2012. Table A-03 provides general information on new lines requiring new right-of-way (ROW).

The Commission opened docket 137-EI-100 to investigate and gather information to help determine a policy framework for good planning practices. On March 23, 2006, the Commission released Commission staff's final report and concluded the docket.

Reliability Assessment

Assessments pertaining to the adequacy and reliability of the state's electricity supply, along with assessments of competitive inputs, pricing and environmental concerns show that the state of Wisconsin continues to make great strides and improvements that assure reliable electricity supply.

Natural Gas Prices

The rate of price increases in natural gas was phenomenal in 2005. These price increases are having a noticeable impact on electric generation costs.

Energy Efficiency and Renewable Resources

2005 Wisconsin Act 141 was recently enacted and will substantially revise the funding and structure of energy efficiency and renewable resource programs in Wisconsin. The legislation is based on the recommendations of the Governor's Task Force on Energy Efficiency and Renewables.

There are several sources of renewable generation presently in Wisconsin. In addition the state's energy utilities and IPPs have proposed 15 new wind power projects for construction in the next several years.

Public Health and Safety and Environmental Protection

Different power plant technologies and fuels used to fulfill the state's energy demand produce tradeoffs between public health and environmental impacts versus need and cost. As part of Conserve Wisconsin, Governor Doyle has asked the Commission and the Department of Natural Resources (DNR) to investigate Integrated Gasification Combined-Cycle (IGCC) technology and its potential for the future energy needs of Wisconsin.

Rates

Changes in Wisconsin rates for residential, commercial and industrial rate classes are shown in Tables 8-01, 8-02 and 8-03. Wisconsin's average commercial and industrial rates are below the national averages. Different regulatory compacts exist in neighboring states, much more so than in the recent past. The ability to make rate comparisons between states is not straightforward.

Topical Questions to Aid Commission Policy Direction

Several questions were put forth by the Commission during the initial data gathering phase of this SEA. Responses have been summarized and presented in the body of this report.

Future Challenges

Specific regulatory policy issues regarding generation, transmission, energy efficiency, renewables and rates will be addressed by the Commission and are presented in the body of this SEA.

ELECTRIC DEMAND AND SUPPLY CONDITIONS IN WISCONSIN

An electric provider is defined for SEA purposes as any entity that owns, operates, manages, or controls or who expects to own, operate, manage, or control electric generation greater than 5 megawatt (MW) in Wisconsin (see Figure 2-01). Electric providers also include those entities providing retail electric service or who self-generate electricity for internal use with any excess sold to a public utility. Major retail electricity providers that submitted demand and supply data for this SEA include: American Transmission Company LLC (ATC), Madison Gas and Electric Company (MGE), Manitowoc Public Utility (MPU), Northern States Power—Wisconsin (NSPW) (d/b/a Xcel Energy, Inc. (Xcel)), Superior Water, Light and Power Company (SWL&P), Wisconsin Electric Power Company (WEPCO) (d/b/a We-Energy), Wisconsin Power and Light Company (WP&L) (d/b/a Alliant), and Wisconsin Public Service Corporation (WPSC). These major retail providers were required to include supply and demand data for any wholesale requirements that they have under contract. This action streamlined data reporting and reflected current market activities. Demand and supply data were also provided by Dairyland Power Cooperative (DPC) and Wisconsin Public Power, Inc. (WPPI) on behalf of their member cooperatives and municipal utilities. Comments were received by Citizen's Utility Board (CUB), Clean Wisconsin, RENEW Wisconsin, Wisconsin Industrial Energy Group (WIEG), Wisconsin Manufacturers and Commerce (WMC), and the Wisconsin Paper Council (WPC).

Figure 2-01 Map of Major Electric Generation Plants in Wisconsin

Table 2-01 shows the aggregated responses of the entities providing data for this SEA. Only confirmed supply resources are used in this aggregation. Contracts that expire but have not been renewed are not carried forward, even though it is likely that some contracts will either be renewed or replaced with other contacts for energy or capacity. Planning reserves are estimated to be adequate through 2012.

Table 2-01 Aggregated Responses of Entities Providing Data for this Draft SEA

Line		2004	2005	2006	2007	2008	2009	2010	2011	2012
		Historical Actual System Values				*Forecasted Planning Values*				
	Summer Peak Electric Demand (MW)									
1	Non-Coincident Peak Load Data & Forecast	13,593	15,184	16,002	16,397	16,796	17,155	17,508	17,849	18,047
2	Direct Load Control Program	-124	-180	-247	-260	-268	-273	-277	-282	-286
3	Interruptible Load	-265	-315	-675	-675	-678	-682	-683	-682	-682
4	Capacity Sales Including Reserves	752	770	862	802	831	761	741	576	580
5	Capacity Purchases Including Reserves	-797	-787	-805	-766	-694	-752	-730	-592	-593
6	Transmission Loss Responsibility Associated with Purchases	15	23	24	26	26	26	27	27	27
7	Miscellaneous Demand Factor, Voltage Control	-599	-597	-636	-638	-637	-637	-639	-639	-639
8	Miscellaneous Demand Factor #2 (identify)	0	0	-5	-10	-17	-24	-24	-24	-24
9	Miscellaneous Demand Factor #3 (identify)	0	0	0	0	0	0	0	0	0
10	Miscellaneous Demand Factor #4 (identify)	0	0	0	0	0	0	0	0	0
11	**Adjusted Electric Demand**	**12,574**	**14,097**	**14,519**	**14,875**	**15,359**	**15,573**	**15,923**	**16,233**	**16,429**
	Electric Power Supply (MW)									
12	Owned Generating Capacity, Used For Wisconsin Load	13,177	12,959	13,364	13,366	13,597	14,713	15,268	15,973	16,290
13	Merchant Power Plant Capacity Under Contract, Used For Wisconsin Load	2,572	3,246	3,609	3,570	3,117	2,540	2,540	2,533	2,283
14	Unit Retirements	0	-228	0	0	0	0	0	0	0
15	New Owned or Leased Capacity Additions	0	664	60	60	952	615	765	386	310
16	Capacity Changes at Existing Units	0	10	35	14	35	35	35	25	133
17	System Basis Capacity Purchases Without Reserves	806	644	360	144	94	94	94	94	94
18	Unit Basis Capacity Purchases Without Reserves	503	383	382	412	385	349	367	367	381
19	Transmission Loss Responsibility Associated with Purchases	-3	-3	-3	-1	-1	-1	-1	0	0
20	System Basis Capacity Sales Without Reserves	-147	-335	0	0	0	0	0	0	0
21	Unit Basis Capacity Sales Without Reserves	-303	-238	-238	-238	-238	-238	-238	-238	-238
22	Miscellaneous Supply Factor, Scheduled Outages	0	0	0	0	0	0	0	0	0
23	Miscellaneous Supply Factor #2 (identify)	-166	-151	-19	148	271	72	-85	-98	37
24	Miscellaneous Supply Factor #2 (identify)	88	88	88	88	88	88	88	88	88
25	Miscellaneous Supply Factor #3 (identify)	0	0	0	0	0	0	0	0	0
26	**Electric Power Supply**	**16,528**	**17,040**	**17,639**	**17,563**	**18,299**	**18,266**	**18,832**	**19,130**	**19,378**
	Reserve Data									
27	Reserve Margin	31.4%	20.9%							
28	Planning Reserve Margin			21.5%	18.1%	19.1%	17.3%	18.3%	17.8%	17.9%
	Additional Resources That Could Have Been Dispatched But Were Not (MW)									
29	Direct Load Control Program	1	-28	16	16	16	16	16	16	16
30	Interruptible Load	275	306	16	16	15	15	15	15	15
31	Miscellaneous Demand Factor, Voltage Control	-11	-11							
	Transmission Data - Firm Interface Capacity Counted for Reserves (MW)									
32	Resources Utilizing MINN-WUMS Interface	306	575	175	75	-150	-150	-150	-150	-150
33	Resources Utilizing CE-WUMS Interface	1,010	830	780	730	630	500	350	350	300
34	Resources Utilizing Upper Michigan-Wisconsin Interface	475	475	475	475	475	475	475	475	475
35	**Total**	**1,791**	**1,880**	**1,430**	**1,280**	**955**	**825**	**675**	**675**	**625**

Peak Demand and Supply

Demand

The Commission compiled substantial information on peak electric demand and energy use. Demand is a measure of instantaneous use measured in MW. Energy is a measure of the volume of electricity used measured in MWh. Demand for electricity moves throughout both the day and throughout the year. In any day there are peak hours of demand. In the summer the demand usually has one peak in the afternoon hours. In the winter it is common to have a morning and an evening peak. Over the course of a year demand for electricity is higher in the summer, lowest in the spring and autumn "shoulder" months, and a smaller peak appears in the winter. Figure 2-02 and Table 2-02 show historic monthly peaks since 1997 and forecast monthly peaks through 2012.

Figure 2-02 Wisconsin Electricity Demand 1997-2012, Monthly Coincident Peak, MW (Actual Data July 1997-2005; Projected Data August 2006-2012)

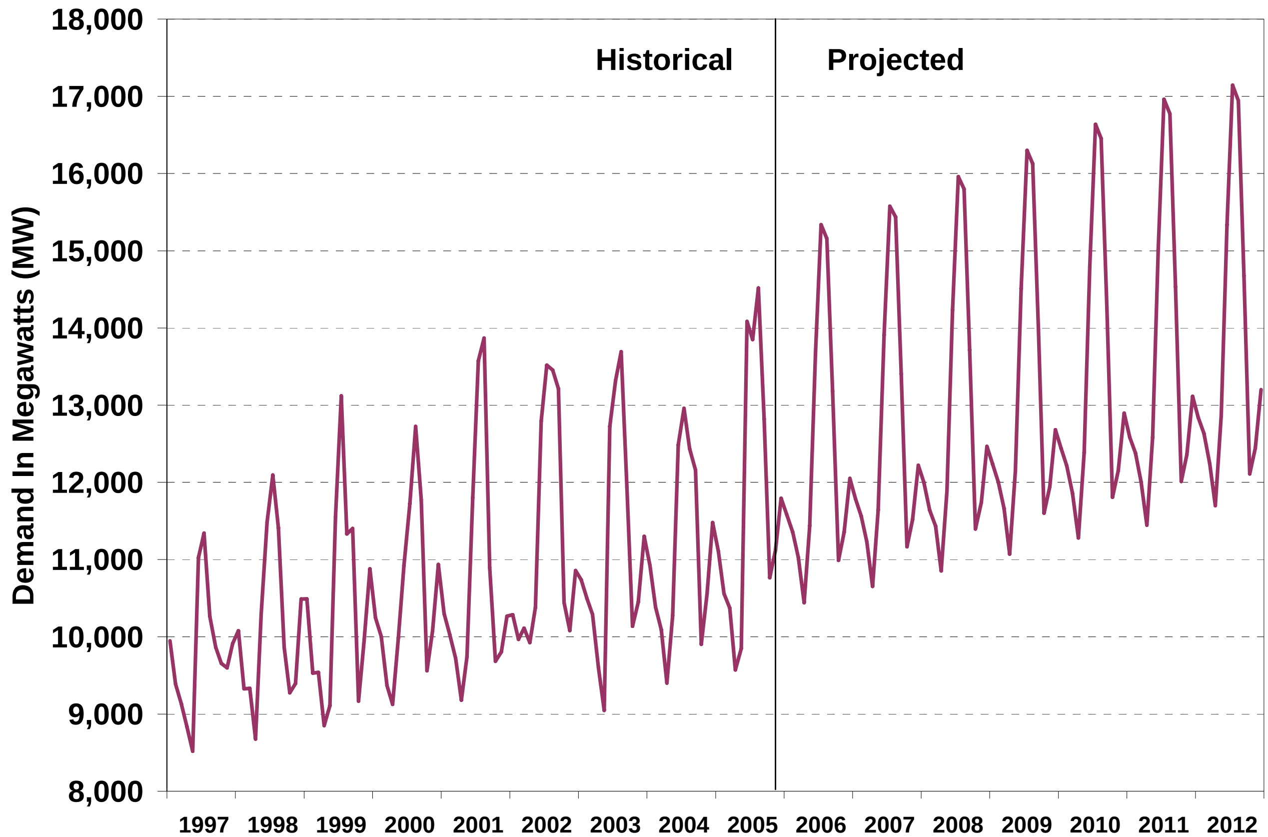


Table 2-02 Assessment of Electric Demand and Supply Conditions, Monthly Peak Demands, MW

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
						Historical (MW)						
1997	9,948	9,386	9,132	8,833	8,518	11,025	11,343	10,265	9,866	9,657	9,598	9,912
1998	10,077	9,326	9,334	8,674	10,286	11,482	12,094	11,411	9,867	9,274	9,394	10,487
1999	10,492	9,531	9,540	8,850	9,108	11,554	13,120	11,331	11,402	9,167	9,953	10,881
2000	10,245	10,004	9,367	9,125	9,986	10,924	11,727	12,726	11,778	9,559	10,082	10,937
2001	10,300	10,032	9,722	9,179	9,742	11,800	13,575	13,870	10,898	9,684	9,805	10,268
2002	10,286	9,965	10,111	9,924	10,381	12,792	13,518	13,454	13,211	10,445	10,080	10,857
2003	10,739	10,498	10,291	9,602	9,048	12,725	13,319	13,694	11,937	10,136	10,450	11,302
2004	10,924	10,384	10,091	9,400	10,273	12,486	12,958	12,437	12,161	9,902	10,557	11,478
2005	11,127	10,678	10,433	9,610	10,000	14,020	13,832	14,323	13,224	11,912	10,833	11,581
						Forecasted (MW)						
2006	11,580	11,351	11,025	10,442	11,439	13,669	15,339	15,158	13,180	10,989	11,353	12,051
2007	11,787	11,562	11,231	10,653	11,644	13,910	15,578	15,437	13,403	11,166	11,517	12,222
2008	11,998	11,638	11,435	10,854	11,887	14,232	15,961	15,799	13,714	11,395	11,742	12,467
2009	12,234	12,002	11,665	11,072	12,153	14,513	16,299	16,127	13,983	11,604	11,946	12,680
2010	12,440	12,217	11,860	11,280	12,391	14,795	16,639	16,456	14,262	11,806	12,150	12,898
2011	12,584	12,379	12,005	11,445	12,581	15,016	16,963	16,774	14,533	12,012	12,357	13,116
2012	12,841	12,634	12,241	11,700	12,867	15,335	17,144	16,944	14,678	12,110	12,442	13,199

Since 1997 peak electric demand has been in either July or August. Peak demand dropped significantly in 2004, a relatively cool summer throughout Wisconsin. In 2005, peak demand climbed significantly and again surpassed the previous monthly peak of August 2001. In 2005, demand in both June and August surpassed the August 2001 peak and July 2005 was just below the previous monthly high demand. Using projections provided by the entities submitting data for this SEA, this pattern of winter and summer peaks is expected to continue into the future. While actual demand will remain dependent upon weather, the overall trend is expected to show continued growth in peak demand, estimated to be approximately 2.0 percent per year through 2012.

Programs to Control Peak Electric Demand

The state's utilities have two forms of peak load management, direct load control and interruptible load. Peak load management is removing load from the system at times when utility resources for generation are not able to meet customer demand for energy. These programs were traditionally expected to be used primarily in the summer months, usually on very hot days when demand for electricity is at its highest. In recent years, under certain circumstances, when the winter peak demand for electricity outpaced available generation, these programs have been used to assure a balance between demand and available supply.

Direct load management gives the utilities the ability to take off the system electric demand such as residential air conditioners. When a utility implements direct load control, affected customers who volunteered to participate in the program receive a credit on their utility bill. While used very sparingly from 2000 through 2003 (between 14 and 86 MW of direct load control were called upon) in recent years the program has been used a bit more, including 123.8 MW in 2004, a cool summer. As shown in Table 2-03, the MW of direct load control available to utilities is much greater than the amount of direct load control that utilities have called upon.

The second form of load management is the use of interruptible load for industrial customers. An industrial customer choosing to select an interruptible load tariff gets a much lower electric energy rate (cents per kilowatt hour) (kWh) by agreeing that their load may be interrupted during periods of peak demand on the system. A utility will notify an industrial customer on an interruptible load tariff that its load will be taken off the system at a specific time. Again, the actual MW of load that are interrupted in a given year is less than the MW of load that are covered by interruptible tariffs. In any given year the need to utilize this form of load control will depend upon generation supply that is available on the days when peak demand happens. In 2006 interruptible load is expected to be about 3.8 percent of the electric power supply (674.9 MW of interruptible load out of 17,639 MW of projected electric power supply). By 2012 interruptible load is expected to drop to 3.5 percent of projected electric power supply. This is due to the expected growth in electric power supply between now and 2012.

Table 2-03 Available Amounts of Programs and Tariffs to Control Peak Load, MW

	Direct Load Control (MW)	Interruptible Load (MW)
	Historical	
1997	169	677
1998	162	794
1999	173	773
2000	169	664
2001	185	637
2002	200	583
2003	186	554
2004	124	265
2005	108	315
	Forecasted	
2006	174	647
2007	185	647
2008	191	650
2009	194	654
2010	196	655
2011	199	654
2012	201	654

Peak Supply Conditions: Generation and Transmission

2005 was a bellwether year for new generation and transmission in Wisconsin. As discussed in more detail below, over 1,300 MW of new generation capacity became commercially operational in Wisconsin in 2005. A new 345 kilovolt (kV) transmission line between the Wempletown substation in northern Illinois and the Paddock substation near Beloit became commercially operational in 2005 creating the first new high voltage interstate transmission connection into Wisconsin in several decades.

As noted in Table 2-01, the planned reserve margin for 2006 is expected to jump to 21.5 percent. Even with the rather robust growth in peak demand indicated by the utilities of approximately 2.0 percent per year through 2012, the significant additional new generation coming on line through 2010 is expected to keep planning reserve margins near or above 18 percent through 2012.

With the new generation coming on line within Wisconsin, the amount of firm, contracted electric generation capacity to be imported through the Commonwealth Edison Company (CE) Wisconsin/Wisconsin Upper Michigan System (WUMS) transmission interface used for planning reserve margin calculations is expected to drop from slightly over 1,000 MW in 2004 to 300 MW by 2012.

New Generation

Wisconsin is in a multi-year expansion period for electric generation that will expand in-state generation capacity by almost 5,000 MW through 2010 from about 14,000 MW in 2003. In 2004 the Riverside combined-cycle facility (600 MW) and the Kaukauna combustion turbine (CT) (55 MW) began commercial operation. In 2005 the Port Washington North combined-cycle (545 MW), the first side of the Fox Energy Center combined-cycle (310 MW), the West Campus Cogen facility (150 MW), and the Sheboygan Falls CT (300 MW) came online.

Over the next five years, through 2010, over 3,000 MW of additional, new generation is expected to be brought into service. These new facilities will include three new, large coal-fired units with over 1,700 MW of capacity, the first new, coal-fired baseload plants in Wisconsin since the early 1980s. Over 400 MW of new wind powered generation are expected to become part of the Wisconsin generation mix between 2006 and 2007. Over 500 MW of combined-cycle capacity is expected to be fired by natural gas along with a 55 MW boiler firing petroleum coke and a 100 MW generation addition from an upgrade of a nuclear powered plant.

The new generation, as noted above, will both reduce Wisconsin's reliance on the currently congested transmission grid connections to Illinois and will maintain a robust planning reserve margin through 2012.

Meeting Supply and Demand Needs

Energy use continues to increase at approximately 2 percent per year. 2004 saw less of an increase in total electric sales primarily due to a cooler than normal summer. Final 2005 sales have not been tabulated but preliminary load information indicates the warmer than normal summer resulted in sales levels above 2004 and are expected to be in line with average historical growth of approximately 2 percent per year. Energy sales are shown in the Figure 2-03.

Figure 2-03 Sales by Wisconsin Electric Utilities 1970-2004, GWh

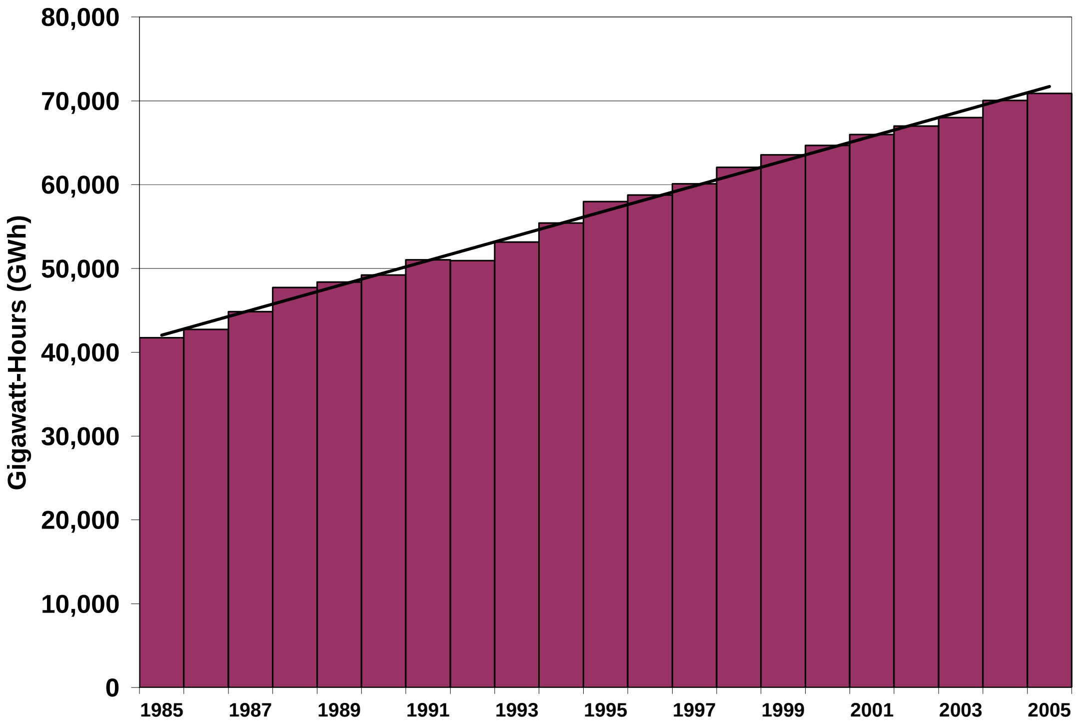
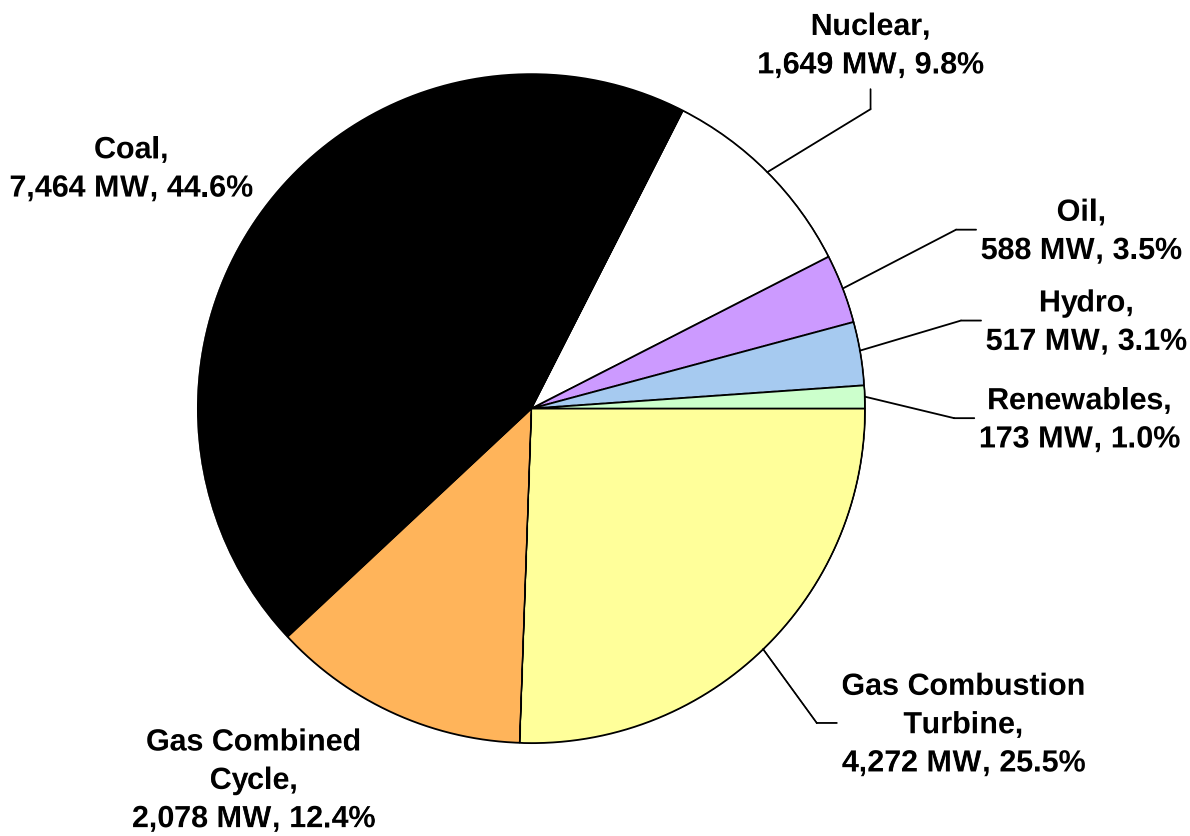


Figure 2-04 Estimated July 2006 Electric Generation Capacity by Fuel Type – Summer Rating, MW



Nearly 85 percent of the total generating capability within Wisconsin uses fossil fuel to produce electrical energy. Figure 2-04 shows the estimated MW capacity by fuel type for the summer of 2006.[1]

[1] Chart includes the Presque Isle Power Plant located in the Upper Peninsula of Michigan whereas the SEA 2002 Report did not include this plant. Northern States Power and WPPI generation located in Minnesota however is not included.

Figure 2-05 Actual Electric Generation by Fuel for 2004, MWh

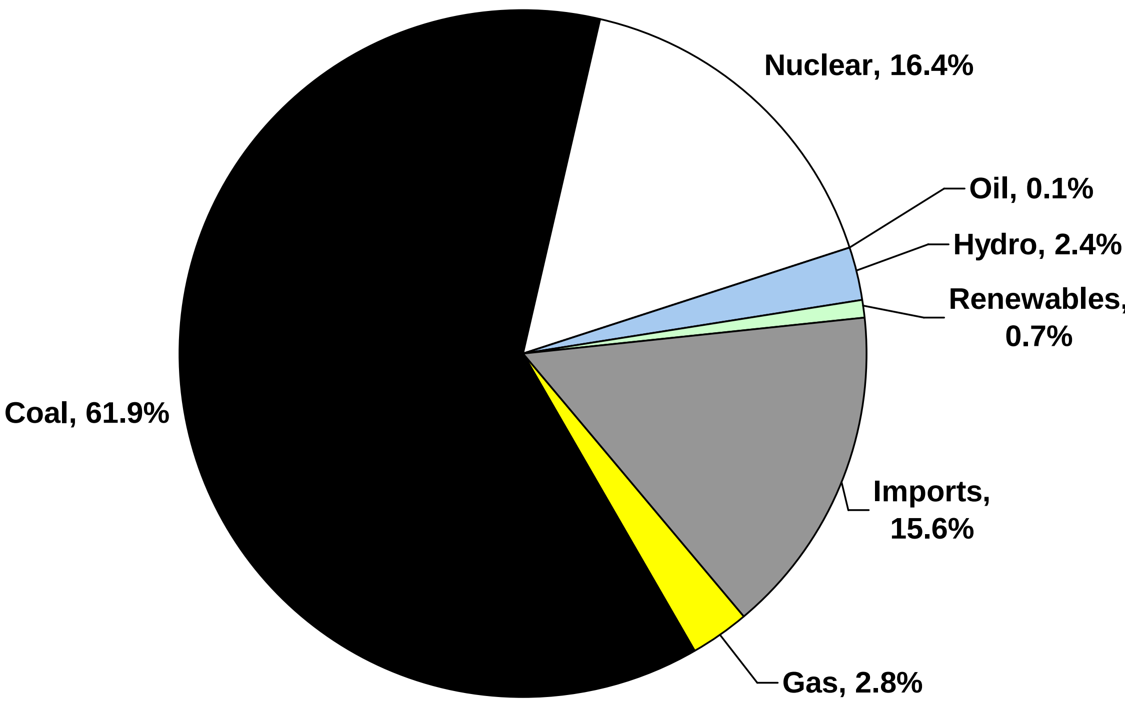


Figure 2-05 indicates the MWh of energy produced by fuel type for year 2004.[2] It shows that 78 percent of the energy consumed in Wisconsin came from either coal or nuclear generation.[3]

Figure 2-06 illustrates the magnitude and mix of new electric generation.

[2] Chart includes imported power and the output from the Presque Isle Power Plant is included in the coal percentages.

[3] 15 percent of energy is considered imports where the generation source is not defined.

Figure 2-06 New Utility-Owned or Leased Generation Capacity, 2005-2014

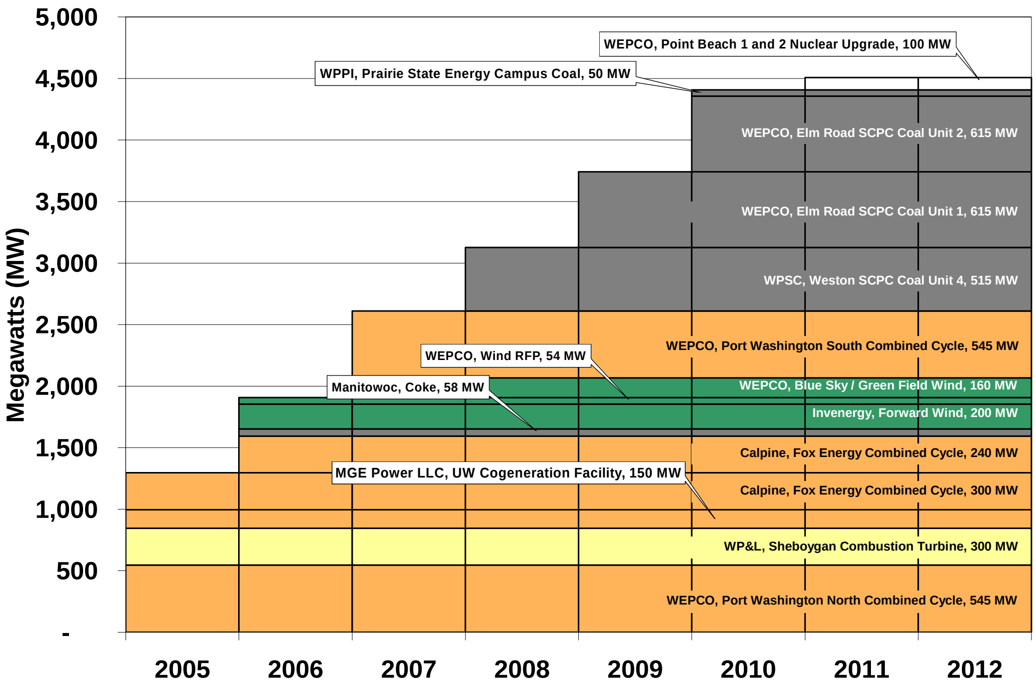


Table A-01 contains the list of generation projects in which there is some certainty to their online date for commercial operation. There are two additional projects where much uncertainty still exists. WP&L has announced a need for a baseload facility with a potential start date of 2012. Sites being examined include WP&L's preferred site at Nelson Dewey near Cassville and an alternative site at Columbia near Portage. Likewise, WPSC is examining a potential baseload facility that may begin construction before 2012. Sites being examined include Weston in Marathon County and the Golden Sands project near Plover.

PSC and Electricity Providers Have Successfully Addressed Supply Adequacy

One of the key reliability measures, but not the only one, is whether the state has adequate electric supply resources to meet its load obligations. An examination of expected planning reserve margins is one way to gauge whether this is the case. Since 1997, the Commission has required the state's utilities to plan for an expected reserve margin of 18 percent, meaning that anticipated supply resources should be at least 18 percent above expected load. Anticipated supply resources include existing generating units, those under construction with expected commercial in-service dates during the relevant SEA year, as well as signed purchased power or leasing agreements with independent power producers or utility affiliates.

Significant progress has been made by electricity providers in meeting the 18 percent planning reserve margin requirement. This is the case not just for the next year or two, but over the expanded time span of 2006 to 2012. Table 3-01 shows the projected planning reserves for the relevant years in all prior SEAs as well as for this draft SEA. The major conclusion is that the state's providers are clearly meeting the expected 18 percent reserve margin requirement with ease, as compared to results in prior

SEAs. This success is due to Commission approval of a significant supply construction program brought forth by the state's electricity providers. In essence, the probability that Wisconsin will have inadequate supply resources in the 2005-2012 timeframe is small. This is in contrast to the reliability crisis that occurred in the mid to late 1990s.

Table 3-01 Forecast Planning Reserve Margins from SEA

Planning Year	Final SEA2000	Final SEA2002	Final SEA2004	Draft SEA2006
2001	17.95%			
2002	17.44%			
2003		19.07%		
2004		20.86%	18.30%	
2005			17.43%	
2006			14.97%	21.50%
2007			16.13%	18.10%
2008			12.80%	19.10%
2009			10.00%	17.30%
2010			11.00%	18.30%
2011				17.80%
2012				17.90%

Note: Shaded areas reflect either data was not available because the particular SEA did not cover those years or the fact that a forecast makes no sense for a historical year. The SEA was expanded to cover seven years of forecast data in 2004; prior SEAs only examined two years.

Trends in Generation Ownership

There have been several significant changes in generation ownership since the last SEA.

In the late 1990s and the first few years of this decade there was a major expansion in electric generation capacity brought about as IPPs built and brought into service natural gas-fired CTs and combined-cycle units. As natural gas prices climbed and nationwide peaking generation capacity was overbuilt, the profitability of these independent power producers fell. Some IPPs such as Mirant and PVG sold their Wisconsin facilities and sites to affiliates of Wisconsin utilities. Other IPPs entered into multi-year contracts for at least some of their capacity with Wisconsin utilities. How the market for peaking capacity evolves is an area of interest well beyond Wisconsin. Efforts to create markets for capacity by regional transmission organizations have not gone smoothly. The Commission continues to monitor this evolving issue.

One area where IPPs have been active is in the development of wind generation projects. IPPs have been active in developing wind projects in Wisconsin and throughout the nation. Even here, though, the financial difficulties facing IPPs have led to collaborative efforts with utilities to find a market for electricity generated by wind.

Another area of significant change in the ownership of electric generation in Wisconsin occurred in early 2005 when the Commission approved the sale of the Kewaunee

Nuclear Power Plant to Dominion Energy Kewaunee (DEK), a subsidiary of Dominion. This marks the first time that a large, baseload electric generation facility in Wisconsin is owned by a company that is not a Wisconsin utility or a Wisconsin utility holding company. This follows a trend in the nuclear generation sector where a handful of companies specializing in the ownership and operation of multiple nuclear power plants sell the electricity, usually under contract, to the former utility owners of the plants.

TRANSMISSION SYSTEM PLANS, ISSUES, AND DEVELOPMENTS

Midwest Independent Transmission System Operator (MISO)

As discussed later in this report, a new feature of electric supply and demand in Wisconsin is the MISO and the MISO Day 2 Market. The MISO Day 2 Market began on the first of April, 2005. Under Day 2, MISO centrally dispatches generation using the real time availability of generation and transmission resources. MISO is a result of the Federal Energy Regulatory Commission's (FERC) orders to create a robust, interstate wholesale market for electricity in the hope that a more efficient use of generation and transmission resources will reduce prices paid by electricity consumers.

The experience under MISO Day 2 has not been fully evaluated. The market is new and the learning curve of both MISO and the MISO participants is not complete. MISO has made transactions for wholesale electric purchases more transparent and it appears that the MISO centralized dispatch may be making better use of the existing transmission resources throughout the Midwest. Concerns regarding the ability of MISO to facilitate transactions across the area covered by the MISO dispatch and transmission territory, and areas such as northern Illinois that are in a territory covered by another regional transmission organization (CE opted to join the PJM Regional Transmission Organization (PJM)), continue to be a concern to both Wisconsin utilities and to the Commission. Costs to operate MISO remain a concern as well.

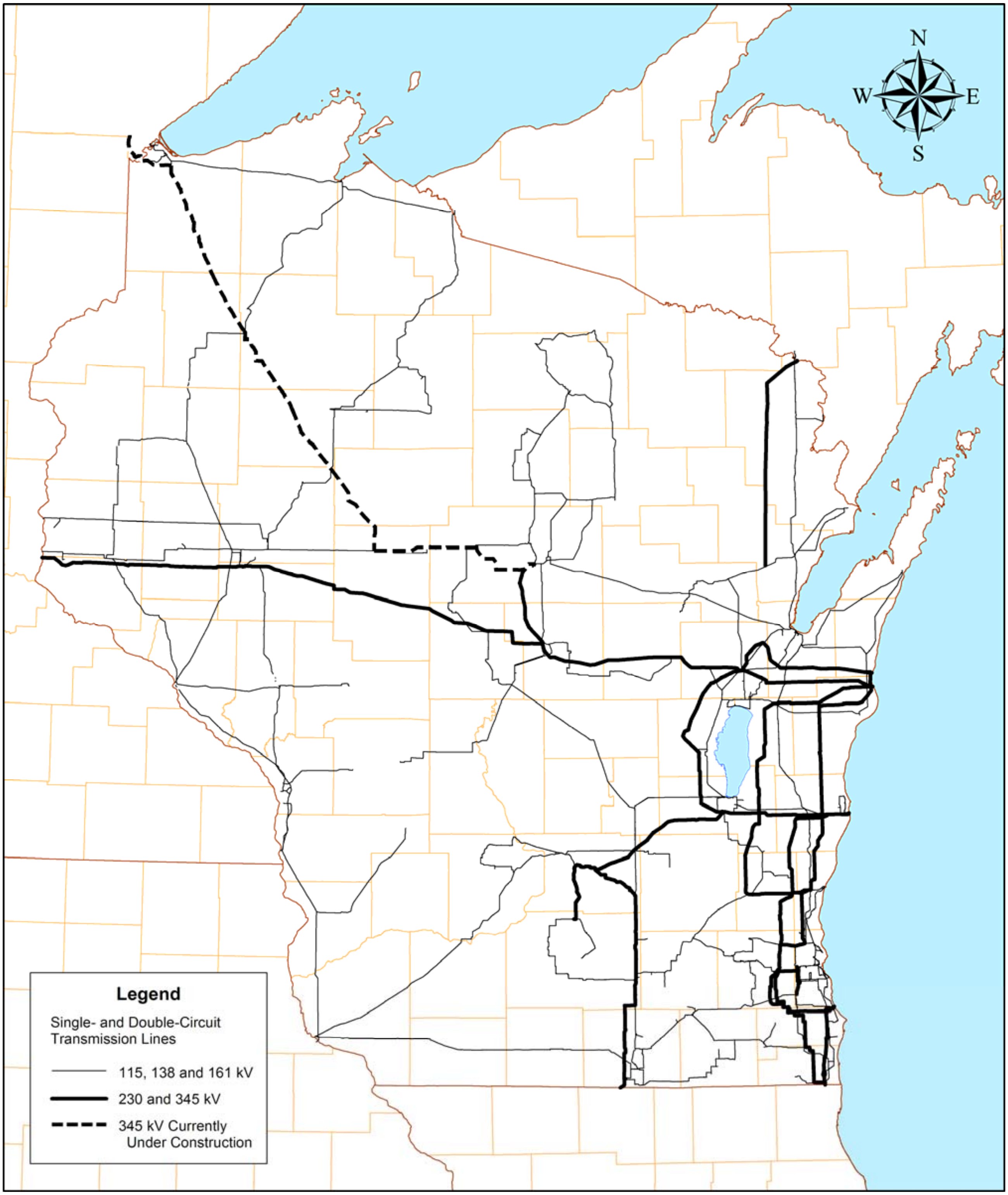
Topical questions and responses regarding MISO operations are summarized in detail later in this report.

Existing Transmission System

Western and eastern parts of Wisconsin are each served by a well-connected high voltage electrical network. However, there are few connections between these two geographical areas of the state. The three companies with transmission systems serving Wisconsin are ATC, Xcel, and DPC. Wisconsin's existing high voltage electric transmission system is shown in Figure 3-01.

Of the top 24 flow gates with constraints in the MISO footprint, Wisconsin, along with the Upper Peninsula, has 12 of them. Twenty-one of the twenty-four have planned solutions by between 2005 and 2009. The last three flow gates (in Iowa) will not be significantly constrained in 2009. For example, the MISO Number 8 Flow Gate constraint (the Lore-Turkey River 161 kV line) in the event that the Wempleton-Paddock 345 kV line is down, has an ultimate, proposed solution of a new 345 kV line from Wisconsin to Iowa or Illinois in 2014.

Figure 3-01 Existing Wisconsin High-Voltage Transmission System



As part of the SEA process, the Commission staff collects information from a variety of sources on the capabilities and limits of the transmission system. Assessments of this information are detailed below.

Transmission Planning

Transmission planning is a constant iterative process of determining local needs, while simultaneously determining the long range development of the Extra High Voltage (EHV) system to accommodate the cumulative load and generation requirements. Some of the major planning factors include:

- Load growth
- New interconnections (load and generators)
- System performance and reliability
- Infrastructure repair and replacement
- Transmission service requests
- Transaction or congestion limitations
- Regional system support

ATC, Xcel and many other Midwest transmission owners belong to MISO, which began operations in 2001. MISO is one of the Regional Transmission Organizations (RTO) that was created pursuant to FERC orders governing operation of the nation's interconnected transmission systems.

Locations and Descriptions of Proposed Transmission Projects in Wisconsin

By state statute, this SEA is to report all transmission lines designed to operate at voltages above 100 kV on which transmission providers propose to begin construction before 2012, subject to Commission approval. "Construction" means building new lines, rebuilding existing lines, or upgrading existing lines. Building new lines requires new transmission structures and, likely, requires new right-of-way (ROW). Rebuilding or upgrading existing lines may also require new structures or new ROW.

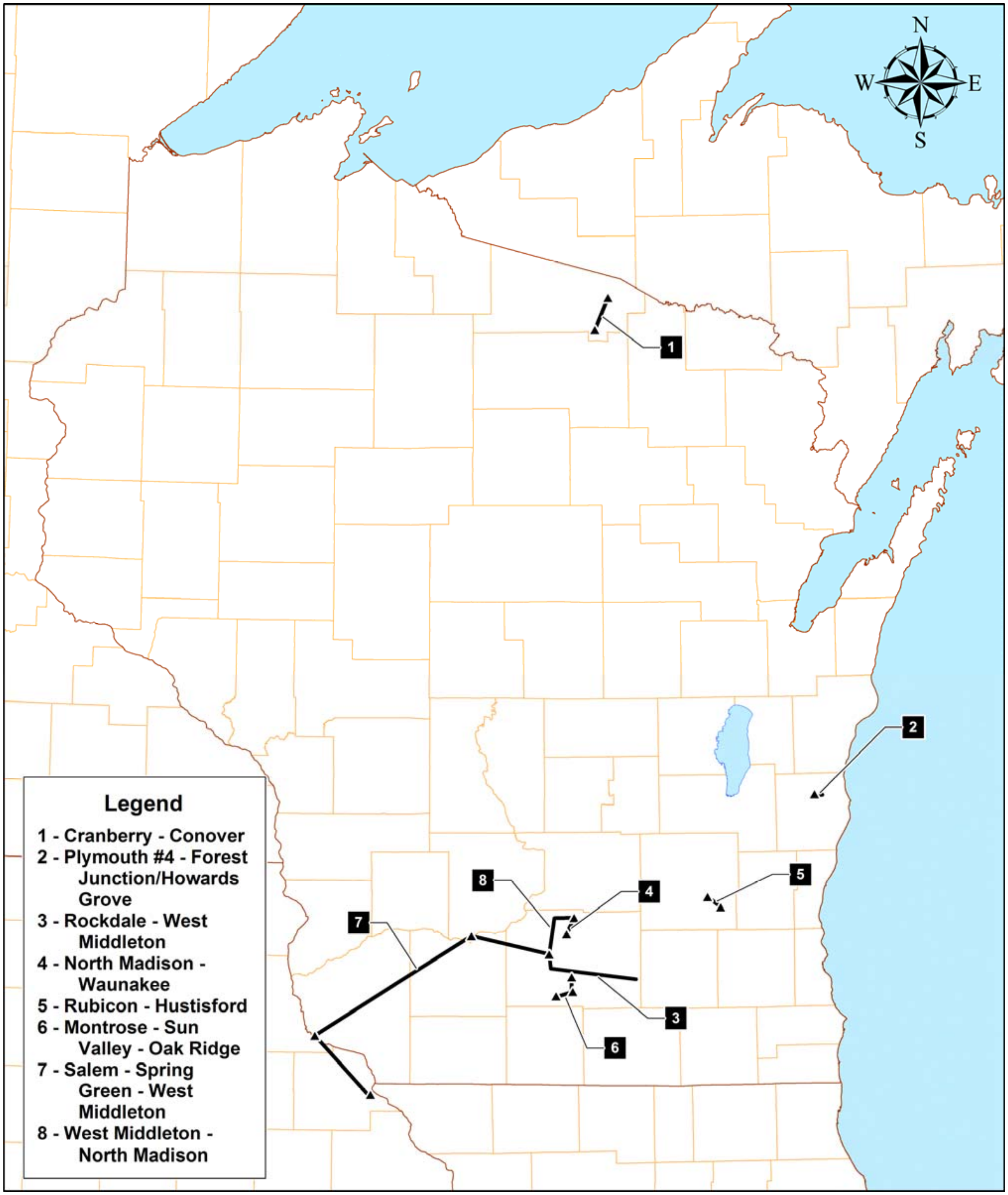
To rebuild a line means to modify or replace an existing line; in other words, to keep it at the same voltage and improve its capacity to carry power through new hardware or design. To upgrade an electric line means to modify or replace an existing line, but at a higher voltage. An upgrade also improves the line's capacity to carry power. Both rebuilding and upgrading may require some (or many) new, taller structures. New ROW may also be needed if the new structures require a wider ROW, or if the line route requires relocation to reduce environmental impacts. Either way, rebuilt or upgraded transmission lines usually need significantly less new ROW than new lines.

The primary reasons for needing additional transmission lines may include one or more of the following:

- Growth in an area's electricity use, which often requires new distribution substations and new lines to connect them to the existing transmission system, or needed increased capacity of existing transmission lines;
- Aging of existing facilities that has resulted in reduced reliability due to poor condition;
- Maintenance of system operational security for the loss of any one transmission or generation element;
- Increased power transfer capability;
- Generation interconnection agreements and transmission service requirements for proposed (or approved) new power plants.

In general, the higher a line's voltage, the more power it can carry. As a consequence, the higher-voltage transmission lines are important in delivering large amounts of power on a regional basis, and the lower-voltage lines primarily deliver power over a more limited area. The ability to deliver power reliably to local substations and the ability to import power from, or export to, other regions, are both important functions in providing adequate, reliable service to customers.

Figure 3-02 Proposed and Approved High-Voltage Transmission Line Additions Involving New Rights-of-Way



Regional Developments

MISO Market

As previously stated, MISO began its Real-Time Market on April 1, 2005. The months since April have seen a different pattern of dispatch than in the past. Some market participants report increased transmission access and others report costs that seem higher than past experience. There have been several cost benefit studies with a range of benefits being expressed. One of the most recent studies by the consulting firm ICF Resources, LLC (ICF) claims to show about a 5 percent improvement in operations. A similar study for PJM had a similar range of benefit. MISO claims a higher benefit for Wisconsin. These studies are complex with forward and back casting simulations with different business rules. The Commission views all estimates as preliminary at this time and in need of full scrutiny. It is not certain if the analysis includes MISO operating costs. To normalize the effect of other changes, Commission staff has identified about 40 factors that should be considered with the simulations. The improvement of 5 percent is significant in dollars, knowing the typical market settlement is approximately $3.1 billion per month. A recent study conducted by ICF indicates the MISO Day 2 operation produces $220 million to $385 million of energy production cost savings each year. One of the continuing debates is the allocation of benefits to costs and causation. Many costs are now spread across the footprint of MISO members with the assumption that, in total, all load serving entities will benefit collectively. Some parties disagree on the amount of their allocated cost assessments as those types of operational costs were not incurred before the market started.

There are six MISO task teams being initiated for the limited purpose of addressing 73 specific market improvement items. These task forces are temporary but are to address such issues as: North American Electric Reliability Council (NERC) compliance, operating reserve coordination, CT use and price setting, unit commitment, net scheduled interchange, and market information dissemination. These teams will attempt to improve the efficiencies of the market while maintaining regional reliability.

MISO Transmission Expansion Plan 2005 (MTEP05)

The MTEP05 was issued in June 2005. It analyzes 15 states in the upper Midwest from the Dakotas to Kentucky and covers approximately 146,000 MW of generation and 97,000 miles of transmission. The Pennsylvania based PJM RTO is adjacent to, and also inter-mingles with, MISO. FERC requested a joint and common market be developed for the two RTOs when FERC allowed CE to join PJM. The area covered by the MTEP05 is shown in Figure 3-04. Note there are several seam issues with non-RTOs and also non-MISO members.

Figure 3-03 NERC Reliability Councils 2006

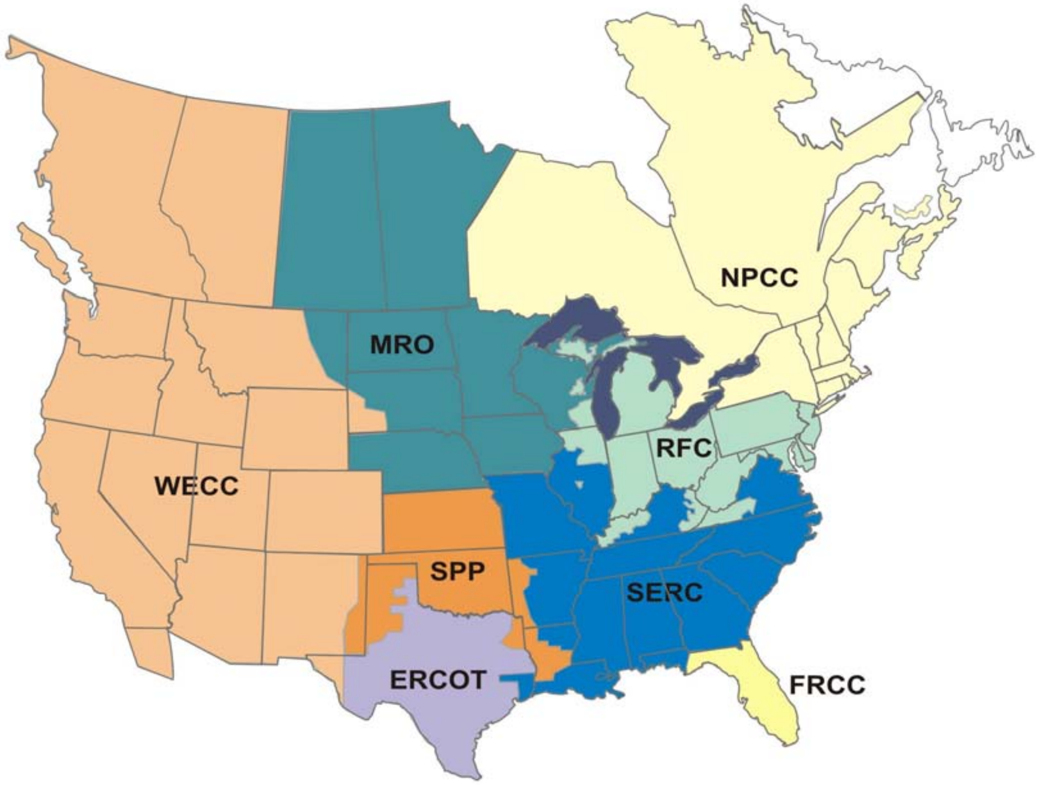
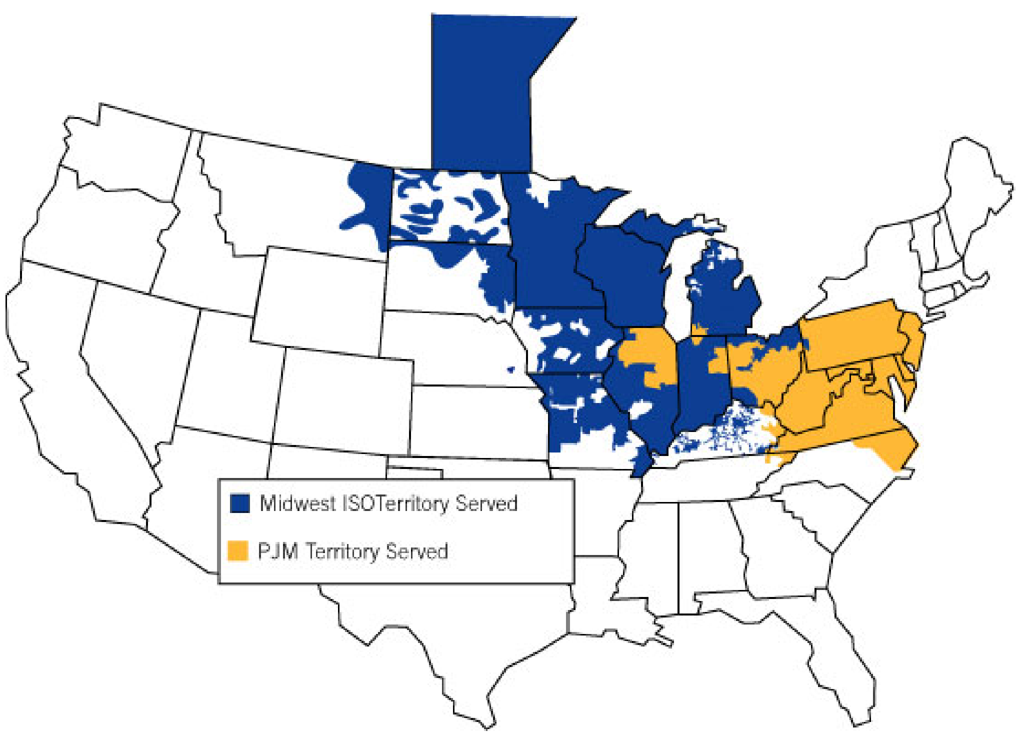


Figure 3-04 Detailed MISO and PJM Regional Transmission Organization Areas



MTEP05 covers the planning years through 2009 as approved in June 2005. MISO developed the MTEP05 to ensure the reliability of the transmission system that is under its operational and planning control. The plan also identifies critically needed expansion to support a competitive supply of electricity. The plan considers all market perspectives, including demand-side options, generation locations, and transmission expansions.

Some of the key findings from the MISO transmission plan are:

- The transmission owners have 615 planned or proposed projects totaling approximately $2.91 billion, primarily to maintain reliability.

- Of the top 24 flow gates with constraints, 21 have planned solutions by 2009. Three lines in Iowa will not be significantly constrained in 2009.

- MISO has conducted additional sub-regional system reliability assessments including load deliverability and operational concerns.

- Transmission expansion exploratory studies in the upper Midwest are continuing to determine the most efficient set of EHV (=> 230 kV) transmission lines for delivery of energy from clusters of wind and coal generation west of Wisconsin to the market.

MISO Transmission Expansion Plan 2006 (MTEP06)

The MTEP06 process began in the summer of 2005. The schedule for completion and approval by MISO stakeholders is November 2006. The MTEP06 includes more objectives and comprehensive analysis than MTEP05. Some of the <u>newer</u> objectives include:

- Coordinate transmission plans with neighboring RTOs and non-RTOs.

- Identify and recommend transmission system upgrades for more efficient operation of the energy market.

- Seek the development of an optimized transmission plan by:

    - Reviewing RTOs' submitted plans and eliminating duplicative transmission plans.

    - Identifying potential non-transmission solutions (to reliability issues) such as demand reductions or new generation additions, where such potential solutions are appropriate.

- Provide information relative to expectations of Financial Transmission Rights (FTR) coverage under the proposed regional plan.

The MTEP06 assumes significant activity in the 2006 and 2011 model years with the planned and proposed transmission projects, and with the known generation interconnection studies. The types of analysis that will be performed in MTEP06 include:

- Steady State Analysis, including NERC Categories A, B, C and D
- Dynamic Stability Simulations
- Voltage Stability and Reactive Supply Analysis
- Load Deliverability Analysis
- Small-Signal Analysis
- Transfer Analysis

There will be additional evaluation of the comparative project investment costs and the costs of alternative non-transmission solutions that would also resolve the identified reliability issues. Some of the alternative solutions could include re-dispatch, effectiveness of demand side concepts, or new generation siting options.

The identification of opportunities for more efficient dispatch will occur with checks of all the significant constraints. MISO will then compare the market participants' lowest cost potential solutions (*i.e.* transmission, demand response, generation) to the to highest cost constraints and determine a reasonable price cutoff for consideration.

MISO will also identify large scale, commercially beneficial projects. MISO has a proposal to calculate and estimate the net economic benefits of economic upgrade projects. The calculation calls for the annual economic benefits to be estimated for each year for a 10-year period from the proposed in-service year. The present value of the levelized annual fixed charges associated with the revenue requirements for the projects will be determined using the discount rate applicable to the funding entity. The same discount rate will be used to determine the present value of the economic benefits.

Besides continuing to study other upper mid-west exploratory projects, MISO will address the Southern Illinois/Southern Indiana/Kentucky/TVA in one study. Another new exploratory project is titled the "MISO Vision Project." This project has three aspects:

1. Move 10,000 – 20,000 MW associated with new wind and coal from the western side of MISO to the eastern side of MISO.

2. Investigate the use of channeled transmission to avoid overhead line issues.

3. Incorporate U.S. Department of Energy (DOE)/Homeland Security/Department of Transportation (DOT) into the process.

ATC Access Study Initiative

ATC began an Access Study Initiative in 2004. The process includes obtaining customer and stakeholder input on the potential benefits, costs, and impacts of improving access. Some of the issues include: chronic transmission limits, economic losses, reliability, strategic operating flexibility, construction costs, and societal impacts (including environmental). The Commission opened docket 137-EI-100 to investigate and gather information to help determine a policy framework for good planning practices. This docket is explained more fully in the Future Challenges section of this report.

Reliability Council Changes

The electrical power system in Wisconsin has operated under the oversight of two regional reliability councils of NERC. NERC is a not-for-profit company formed by the electric utility industry in 1968, following the 1965 New York electric system blackout, in order to promote the reliability of the electricity supply in North America through the voluntary use of common planning and operating guidelines. For many years the Mid-Continent Area Power Pool (MAPP) regional reliability council oversaw the northwest and western part of Wisconsin composed of the Xcel and DPC control areas.[4] MAPP also covered Minnesota, Iowa, Nebraska, the Dakotas, and parts of the Canadian provinces of Manitoba and Saskatchewan. That council was changed to the Midwest Reliability Organization (MRO) in 2005. The Mid-America Interconnected Network (MAIN) regional reliability council oversaw the remainder of the state in which transmission service is now provided by ATC. MAIN also covered Illinois and parts of Missouri, Iowa, southern Minnesota, and the Upper Peninsula of Michigan. Control areas inside ATC's Wisconsin footprint are operated by WP&L (Alliant), MGE, WEPCO, and WPSC. The MAIN organization dissolved at the end of 2005 with the members joining new reliability organizations. WEPCO joined the Reliability*First* Corporation (RFC). RFC is the successor organization to three existing NERC councils: MAIN, ECAR and MAAC. WPSC, MGE and Alliant will join the MRO. The RFC began operations January 1, 2006. Some of the Missouri and Illinois members will be joining the Southeast Reliability Council (SERC). See Figure 3-03, NERC Reliability Councils 2006.

RELIABILITY ASSESSMENT

Wis. Stat. § 196.491(2)(a) specifically requires the SEA to assess: (1) the extent to which the regional bulk power market is contributing to the adequacy and reliability of the state's electrical supply; (2) the adequacy and reliability of purchased generation capacity and energy to serve the needs of the public; (3) the extent to which effective competition is contributing to a reliable, low-cost, and environmentally sound source of electricity for the public; and (4) whether sufficient electric capacity and energy will be available to the public at a reasonable price.

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[4] A control area is a portion of the electrical system where generation is controlled to meet electrical demand (load) within that area.

The analysis that follows incorporates data submitted by the electricity providers in their SEA submission, other data collected by Commission staff, as well as the electricity providers own qualitative discussion of the above important questions. The Commission welcomes additional public input as the SEA process continues as described in the introduction to this report.

Assessment of the Extent to which the Regional Bulk Power Market is Contributing to the Adequacy and Reliability of the State's Electric Supply

New utility-owned generation and a new real time energy market are the significant changes that have occurred since the last SEA. As new generation capacity continues to be brought into service the amount of capacity purchases from IPPs is expected to drop significantly through 2012. As can be seen in Table 2-01, capacity purchases made on a system basis are expected to drop from 806 MW in 2004 to 94 MW in 2012. Yet, reliability is expected to remain robust with a 2012 planning reserve margin of 17.9 percent, seven years into the future.

Also shown in Table 2-01 is a reduction in the MW of capacity under contract from merchant power plants. Merchant power plant capacity under contract is expected to fall from 3,609 MW in 2006 to 2,283 MW in 2012. This decrease occurs even while counting the sale of the Kewaunee Nuclear Power Plant and the associated power purchase agreement by the former utility owners for the capacity and energy from that facility through its current license.

Planning reserve margins have been a major concern in earlier SEAs. In the second half of the 1990s actual reserve margins fell to less than 10 percent four out of five years. The lowest actual reserve margin fell to 6.7 percent in 1995. By contrast, the actual reserve margin in 2004 was 31.4 percent. Granted, 2004 was a very cool summer, but the reserve margins for 2005 and 2006 are expected to be above 20 percent.

Sufficient capacity is not the Commission's only concern. Getting the power from the generation source to the load is a concern as well. Wisconsin's current transmission system has numerous constraints that limit the unfettered flow of electricity into and within the state. These numerous constraints led MISO to name the WUMS area of Wisconsin and Michigan as a narrowly constrained transmission area. For the next five years there are special protections available to Wisconsin and Michigan to avoid undue prices on electricity in the wholesale market. It is expected that the current and ongoing transmission system expansion and improvements will greatly improve the ability to move electricity into and within Wisconsin by 2010 when the special protections will be withdrawn.

Even with the constraints in place due to current transmission limitations, the MISO market has begun to transform the way the bulk market for electricity operates. Numerous responses to the Commission's topical question about MISO noted that there is much more transparency in the market for electricity; that is, price and availability are more visible and apparent to market participants on a day ahead and real time basis compared to the past. At the same time, short-term bilateral contracts for electricity are becoming much less common. As an analogy, the market for electricity is moving from a real estate type market where each transaction is unique to a commodity-type market, such as the market for oil, where current supply and demand from many players set the price. The expectation that led to the establishment of regional transmission organizations, such as MISO, and the use of real time area specific pricing (known as locational marginal pricing (LMP)) was that these markets and organizations would lead to more efficient generation and dispatch choices and lower the wholesale price of electricity. The Commission remains cautiously optimistic that the anticipated results will be obtained as the MISO market continues to mature.

Assessment of the Adequacy and Reliability of Purchased Generation Capacity and Energy to Serve the Needs of the Public

Purchased generation capacity and energy may be from facilities located within Wisconsin or from facilities located outside of Wisconsin. For this analysis, NSPW and SWL&P will be considered separately. These two utilities have Minnesota based affiliates where much of their generation capacity and energy needs are met as though they were part of the affiliates' system. The Wisconsin utilities in the eastern portion of the state are not part of multi-state affiliate networks that dispatch electricity across multiple states as a system. These WUMS utilities were well placed in the late 1980s and throughout the 1990s to make purchases of excess generation capacity and energy, especially in Illinois. Thus, much of past SEA discussions on purchased generation capacity and energy focused on imports of generation capacity and energy.

As the transmission system and especially the transmission connections between Wisconsin and Illinois became constrained, the ability to purchase capacity in other states for Wisconsin, or to purchase energy generated in other states to be delivered to Wisconsin, became problematic.

Again, two things have changed in recent years with respect to purchased generation capacity and energy. First, several new facilities owned by independent power producers have initiated commercial operation in Wisconsin. Second, the aforementioned sale of the Kewaunee Nuclear Power Plant to DEK has broadened the market to include baseload generation in addition to the CT and combined-cycle generation that has a much lower capacity factor. The CT market is usually a market that focuses on generation capacity that is only expected to be used approximately 5 to 10 percent of the time. Combined-cycle units have higher capacity costs but are much more efficient. For the higher capacity costs, but lower generation costs, these plants are expected to be used from between 25 percent of the time to perhaps even more than 70 percent of the time, depending upon fuel costs. A nuclear powered baseload plant has very high capacity costs, but very low cost of generation, not including externality costs. For a nuclear power plant, and to a lesser extent a large coal-fired baseload plant, to be commercially viable, they need to be used much more and have utilized capacity factors of 80 percent to even greater than 90 percent.

Comparing the market for purchased generation capacity in 2000 to the same market in 2006 indicates that more of the purchased generation capacity and energy will be from facilities located within Wisconsin. With the purchase of baseload energy, more gigawatt hours of total energy may be purchased than there have been in the past.

The market for purchased generation capacity and energy continues to evolve. The business failure of Enron and deep concerns about the economics of the market for generation capacity for peaking needs has affected electricity markets well beyond Wisconsin. The Commission continues to watch developments at MISO in how generation capacity markets continue to develop. At the same time, the Commission found in the proceeding approving the sale of Kewaunee that concerns, including reliability concerns, can be overcome to allow the sale of a rate base baseload plant with a power purchase agreement that protects Wisconsin ratepayer interests.

Assessment of the Extent to which Effective Competition is Contributing to a Reliable, Low Cost, and Environmentally Sound Source of Electricity for the Public

The issue of reliability has been addressed in the other sections of this report. This section will deal with the low cost and environmentally sound provisions required by statute.

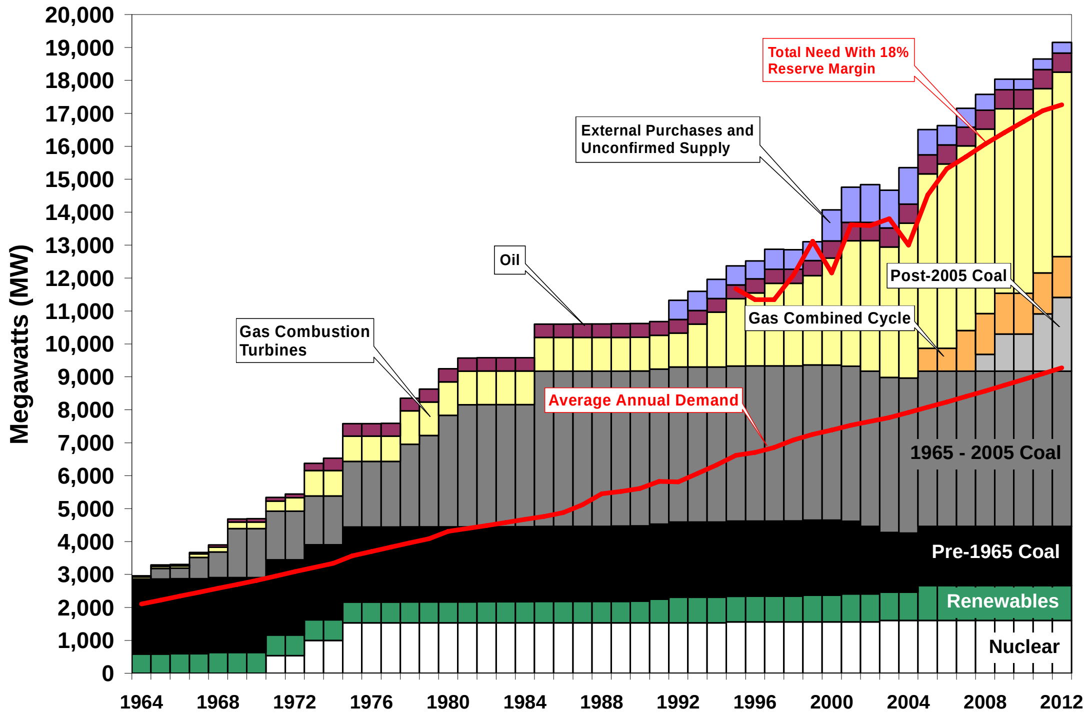
FERC has the authority under federal law to regulate the market for wholesale power. As part of FERC's regulatory agenda, it established rules for regional transmission authorities and allows those regional transmission authorities to establish markets for energy. This has culminated in the Day 2 Market under MISO that sets day ahead and real time prices for energy at a location by location basis throughout the area served by utilities participating in MISO. Most of the major Wisconsin electric utilities are part of MISO.

The MISO market makes the analysis in this section less clear cut than in past SEAs. The market for electricity now has MISO establishing prices based on congestion costs, losses, and energy costs of marginal units. On any given hour of any given day the market clearing price for electricity can move from very low to very high as more expensive units are brought on line to meet the load curve. The price for all electricity is the price set by the marginal unit. Thus, the price of electricity from a baseload plant may have a MISO value that varies from $10 per MWh during off peak time to $200 per MWh during peak time. This is not the price paid by consumers. The transaction can be looked at as such: First, the utility pays MISO $200 and then MISO pays the $200 to the owner of the energy that was put on the grid. If the utility owns, or has the energy (or capacity) under contract, then the utility gets paid back the $200. The cost to ratepayers is the actual cost of generation or the cost of the contract that created the generation. This MISO market has not been analyzed in past SEAs.

In past SEAs, the focus of this section has been on the costs associated with purchased power and on environmental outcomes. As discussed above, the market for purchased power is transforming. The reliance on purchased power contracts for peaking power fired by natural gas appears to be waning. More and more natural gas-fired peaking generation capacity over the next six years is going to be owned directly by the utilities or acquired through leased generation contracts with affiliates of the utilities. At the same time, some of the new wind generation is being developed by IPPs and is being acquired through long term purchases by some Wisconsin utilities. Other Wisconsin utilities are choosing to directly own their wind generation resources. Lastly, entities can use the Day 2 Market to obtain supply, the pricing of which is monitored by an independent party to avoid market manipulation. The prices in that market are also capped at $1,000 per MWh.

What does this mean for this analysis? Figure 4-01 shows that we are moving into fewer purchased power contracts for units with low capital costs but relatively high marginal energy costs. These are the natural gas-fired combined-cycle units and natural gas-fired CT units. At the same time we are seeing more power purchase agreements for relatively high capital costs but low marginal energy cost for such generation as nuclear and wind.

Figure 4-01 Wisconsin Generation Capacity



The final topic in this section is an assessment of whether competitive markets are contributing to an environmentally sound source of electricity for the public. According to conventional economic theory, competitive markets will consider all direct economic costs as well as any indirect costs associated with externalities, such as pollutants, as long as the externalities in question have been regulated by either command and control methods or by some form of monetization in the form of taxes or emission allowance trading, for instance. In cases where legitimate externalities have not been so factored in, the competitive marketplace will ordinarily ignore any of the non-private costs associated with such externalities. There may be some exceptions in cases where the public may be willing to pay a premium for goods or services with a real or perceived better environmental footprint. In Wisconsin, such an example might be individual utilities offering green pricing programs whereby customers may buy wind power.

With this background, competitive power markets have been contributing to an environmentally sound source in the cases of pollutants and externalities that are under public policy supervision.[5] Examples would include sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate pollution. On the other hand, competitive power markets may not be contributing to an environmentally sound source in the cases of pollutants and legitimate externalities that are not under appropriate or adequate public policy supervision. Examples might include mercury deposition, permanent nuclear waste disposal, and greenhouse gases.

Assessment of Whether Sufficient Electric Capacity and Energy will be Available to the Public at a Reasonable Price

The Commission has recently approved CPCNs for three new, large, coal-fired baseload generation units. The Commission has also approved CPCNs for new combined-cycle natural gas generation, wind generation, and CT natural gas generation. As noted in Table 2-01, planning reserve margins are projected to be above, or very close to, 18 percent through 2012. Both the magnitude and the mix of new electric generation appear to answer the statutory question in the affirmative. Wisconsin's electric generation future is in much better shape now than it has been in the past with respect to capacity and energy.

However, several issues remain outstanding on the capacity and energy future.

First, Wisconsin still has several very old, small coal-fired boilers. These units tend to have low levels of efficiency and tend to be much harder to control regarding pollution reduction requirements that have been established by the U.S. Environmental Protection Agency (EPA) through their promulgated Clean Air Interstate Rule and the proposed Clean Air Mercury Rule. It is very likely that some older coal-fired units will be retired rather than controlled. If units are retired it must be recognized that these units have been running as baseload units, so even though their name plate capacity may be small, their contribution to generation is often much larger than the energy generated from, for example, a new CT. The reason is simple—although they are not very efficient and they contribute disproportionately to pollution, they have been cheap to operate. Wisconsin currently has over 5,000 MWh of electricity generated by coal-fired units that were built prior to 1960.

Second, Wisconsin's governor and legislature are currently evaluating the policy options of a renewable energy portfolio requirement. Currently, wind generation is the lowest-cost renewable energy option. A renewable energy portfolio requirement that calls for 2,000 MW of renewable capacity would affect Wisconsin's optimal energy expansion path. By 2006, Wisconsin will have a significant fleet of natural gas-fired

[5] Appropriate public policy supervision assumes that the appropriate amount of control or mitigation takes place. In practice, there is significant ongoing political and scientific debate about the appropriate amount of control or mitigation. Such debate also concerns what constitute appropriate externalities as well.

CTs and combined-cycle units. These units are critical to a generation fleet with significant wind capacity. Wind, while having very low marginal costs of generation, has unpredictable availability. To complement the low and unpredictable availability factor, wind needs to have rapidly available alternative generation capacity to be used and useful. Natural gas-fired CTs and combined-cycle units can fit this need. This may imply a higher capacity utilization for CTs and combined-cycle units. This raises a concern because Wisconsin does have a number of older CTs, some running on fuel oil. These units have been economic to hold onto given their relatively low capacity utilization. However, if wind resources are expanded either in Wisconsin or outside of Wisconsin for use in Wisconsin, some CTs may need to be replaced with newer, more reliable and less polluting units.

The financial benefits and costs of these alternatives will need to be addressed in a contested case for the Commission to fully appreciate all the implications.

NATURAL GAS PRICES

Natural gas price changes affect energy consumers in two major ways. First, many Wisconsin customers purchase natural gas at the retail level for direct consumption. In this context natural gas is used for space heating, cooking, and processing materials, among other uses. Second, natural gas is increasingly being used to fire electric generators. Natural gas price increases therefore affect the cost of providing electricity as well.

In terms of retail purchases, there are three major cost components associated with providing natural gas service to a customer: (1) the cost of extracting natural gas (production), (2) the cost of transporting the natural gas from the production area to the local utility (transmission), and (3) the cost of delivering the natural to the customer's premises (distribution). The Commission regulates only the last of those items. FERC regulates interstate natural gas transmission from production areas to Wisconsin. The price of natural gas at the production level is not regulated. That price is set by the market via the interaction of supply and demand, just as is the price of oil, oranges, or automobiles.

Under current market conditions about 25 percent of a residential gas customer's bill is the result of rates set by the Commission. For a large industrial customer that figure is only about 5 percent. The lion's share of any natural gas customer's bill is the cost charged by the producer.

The rate of increase in producer prices has been phenomenal. For the last decade of the 20th century natural gas producer prices averaged about $2.00 per MMBtu. In this century the average price has risen to over $5.00 per MMBtu, which represents a 150 percent increase. The situation was especially severe in 2005. The average price rose to about $8.00 per MMBtu, which represents nearly a 300 percent increase over the prices paid in the 1990s.

These price increases are having noticeable impact on electric generation costs. In 2005, 60 percent of the electric rate increase amounts approved by the PSC were attributable to natural gas price increases. The Commission recently opened a generic investigation (docket 5-UI-110) which will focus on, among other things, natural gas procurement and cost recovery practices. This generic proceeding will provide the Commission with information that will aid the Commission's policy making regarding natural gas price impacts in Wisconsin.

Solutions to High Natural Gas Prices

There appear to be two fundamental reasons for the rapid increase in natural gas prices: (1) demand has grown at pace that has outstripped supply; and (2) a reduced number of producers in the industry has led to a seller's market. The first issue can be addressed by moderating demand via enhancing the level of energy efficiency and by increasing natural gas supplies. Addressing the second issue is more problematic and would require government intervention.

The high natural gas prices may be a call to re-examine energy efficiency policy. When natural gas was more moderately priced, the incentive to purchase the most efficient equipment was muted. The rapid increase in natural gas prices now makes high efficiency equipment more economically attractive. For example, if increasing insulation levels had a 10-year payback period[6] when natural gas prices were $2.00 per MMBtu, the payback period would be closer to five years under current prices.

The high prices have a corresponding effect on the supply side of the industry. Drilling for natural gas via deep wells may have been prohibitively expensive when natural gas was selling for $2.00 per MMBtu. Drilling that same well today may be cost-effective under current prices. In addition, unconventional facilities, such as liquefied natural gas (LNG) ports, are now being considered as possible means of expanding the supply base. LNG is typically imported from foreign countries with ample natural gas supplies, such as those in the Middle East. At $2.00 per MMBtu shipping natural gas across the ocean is not cost-effective. At $8.00 per MMBtu such trips are economic.

Structural Issues in the Natural Gas Industry

To look only at supply and demand imbalances misses perhaps a more fundamental issue. The market structure of the natural gas industry may be a contributor to the problem. Markets work well under certain conditions. Under other conditions, markets fail to hold prices near the cost of producing the good or service. If market solutions were always best, there would be no need for governmental antitrust review of proposed mergers. When market conditions are not conducive to promoting effective competition, consumers pay more than they should. Sellers earn excess profits. The economy suffers under those conditions.

[6] The payback period is the number of years that it takes for the bill savings from a measure to recover the full cost of installing that measure. For example, if a new furnace costs $3,000 and it saves the customer $300 per year, the payback period is $3,000 / $300 = 10 years.

Markets have the greatest likelihood of working well when there are many independent suppliers, none of which has noticeable size or resources. In contrast to this ideal state, the natural gas industry is dominated by some of the largest companies in the world. These companies can exert not only economic power, but also political power to protect their interests. It would be difficult for proponents of market-based pricing of natural gas to argue that the market worked well in 2005.

The Commission has recently opened a generic investigation, docket 5-IU-110, which will examine natural gas and coal procurement and cost recovery practices in the state.

ENERGY EFFICIENCY AND RENEWABLE RESOURCES

Governor's Task Force on Energy Efficiency and Renewables

In September 2003, Governor Jim Doyle's Task Force on Energy Efficiency and Renewables began its work. This task force was charged with restoring Wisconsin's leadership in conservation and renewable energy. The task force released its report in October 2004. Highlights of the energy efficiency recommendations in the October 2004 report include:

- Every four to five years the Commission should have a proceeding to set overall savings targets for energy efficiency, set funding levels to reach these targets, and consider utility requests to retain a portion of their funds to administer programs in their territory for larger commercial and industrial customers.

- Wisconsin should adopt structural changes to protect public benefits funds, such as a trust fund or an independent fiscal agent to hold funds exclusively for public benefits.

- DOA would continue to be the overall program administrator of public benefits.

- The Commission would oversee independent measurement and evaluation activity.

- The Commission and the utilities would be deemed to have satisfied the requirements of the Energy Priorities Law with respect to customer-side energy efficiency if the utilities meet the funding requirements set by the Commission and these funds are reserved for energy efficiency.

The task force recommended that the governor and the legislature take the following actions to encourage greater use of renewable resources for the generation of electricity:

- Establish a new, higher standard for renewable energy use in the state, averaging 10 percent statewide by 2015. To meet the new standard, each electric provider would be required to increase the portion of its retail sales from renewable resources by 6 percent above its three-year average for 2001 to 2003.

The new standard would also be better integrated with the application of the Energy Priorities Law and the SEA.

- Establish a target for state agencies to purchase at least 10 percent of their electricity from renewable resources by 2007 and at least 20 percent by 2011.

- Create a sales and use tax exemption for customer-owned renewable energy systems such as small wind turbines, solar panels and solar water-hearing services.

- Encourage the research and development of renewable energy systems, particularly anaerobic digesters, in rural Wisconsin.

Another outcome of the Governor's task force was the commissioning of an energy efficiency potential study by the Energy Center of Wisconsin (ECW). The purpose of the study is to aid policy-makers in determining the appropriate energy efficiency goals and funding levels. This study was released in December 2005.

Energy Efficiency and Renewable Resource Act (2005 Wisconsin Act 141)

Legislation passed recently that will substantially revise the funding and structure of energy efficiency and renewable resource programs in the state of Wisconsin. This legislation is based on the recommendations of the previously explained Governor's Task Force on Energy Efficiency and Renewables and provides:

- Statewide energy efficiency programs collectively funded by investor-owned electric and natural gas utilities. Funding for these programs is secured by requiring the utilities to directly contract with a program administrator.

- Allowance for utility-administered and large customer energy efficiency programs.

- Funding level of 1.2 percent of annual operating revenues (about $82.4 million). The Commission may specify, subject to review by the Joint Committee on Finance, a higher funding level based on a list of criteria.

- Commission oversight of the statewide and utility programs. The Commission must conduct, at least every four years, a proceeding to evaluate the statewide and utility programs and to set or revise goals, priorities, and measurable targets for the programs.

- That state agencies purchase at least 10 percent of their electricity from renewable resources by 2007 and at least 20 percent by 2011.

- That each Wisconsin electric provider increase its RPS to 6 percent above its three-year average for 2001-2003. The statewide goal is 10 percent renewable electricity by 2015.

Energy Efficiency

Status of Energy Efficiency Efforts

Conservation and energy efficiency efforts encourage customers to reduce their use of energy. Conservation saves energy or reduces demand by reducing the level of energy services (*e.g.* turning off lights, changing thermostat settings, taking shorter showers, etc.). Conservation generally involves behavioral changes. Energy efficiency is the application of technologies that use less energy while producing the same or better level of energy services. These technologies are generally long-lasting and save energy whenever the equipment is in operation.

The level of electric energy and demand savings achieved through conservation and energy efficiency affects how many power plants or how much transmission capacity needs to be built. Historically, utilities were responsible for both electric and natural gas conservation and energy efficiency services. Major changes to the delivery of conservation and energy efficiency services occurred as a result of 1999 Wisconsin Act 9 (Act 9). These major changes were in response to a sharp decline in utility conservation and energy efficiency spending and savings in the mid-1990s and to address funding and delivery in anticipation of an electric retail access environment. Act 9 established a new funding mechanism, to be administered by DOA for programs for electric and natural gas low-income assistance, energy conservation and efficiency, environmental research and development, and renewable resources. These are called Public Benefits Programs.

In addition to this new funding for conservation and energy efficiency, Act 9 provided for the annual transfer of funds equal to the amount Wisconsin Class A, investor-owned utilities spent for electric and natural gas public benefits type programs in 1998 from the utilities to the Public Benefits Fund administered by DOA. These utilities transfer about $45 million annually to the Public Benefits Fund for the provision of conservation and energy efficiency services. These services are provided through the Focus on Energy (FOE) umbrella. The utilities also retain about $25 million of their 1998 conservation and energy efficiency expenditures for customer service conservation and load management activities. Conservation and energy efficiency services through DOA-administered Public Benefits Programs were first made available to ratepayers in 2001. However, 2003 was the first year of full funding for Public Benefits Programs, as utilities retained some Public Benefits Funds through the transition period. The following graphs address only electric conservation and energy efficiency efforts. They do not include natural gas, renewable energy, or low-income expenditures and savings.

Figure 5-01 shows the aggregate historical and projected electric conservation and energy efficiency expenditures of Wisconsin utilities and DOA for calendar years 2004-2008 and 2012. Figures 5-02 and 5-03 provide the level of electric demand and energy savings, respectively. The charts include the aggregate expenditures and savings of the following utilities: MGE, NSPW, SWL&P, WEPCO, WP&L, and WPSC.

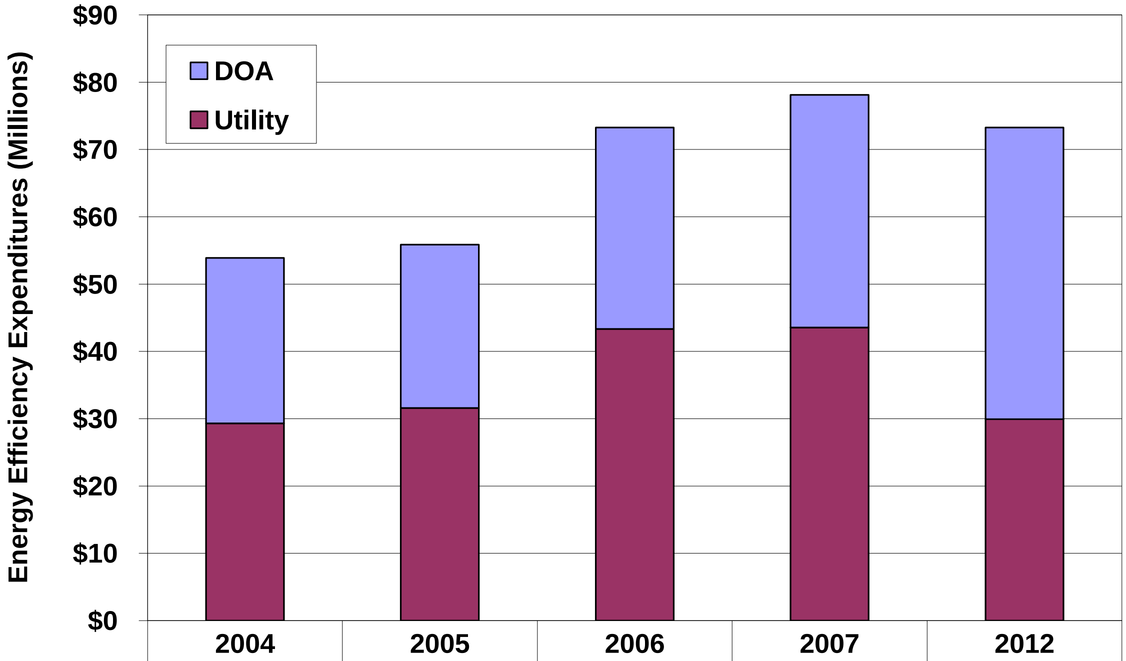
Expenditures and savings for DPC and WPPI are also included.[7] DOA provided actual data for 2004, while the utilities provided actual data for 2004 and 2005. Expenditures and savings for the remaining years are projected. DOA generally reports expenditures and results of Public Benefits Programs on a fiscal year basis. For consistency, Public Benefits expenditures and savings were converted to a calendar year. At the present time, the Public Benefits Program is not fully funded. Full funding of about $62 million annually, including natural gas and renewable energy funding, is assumed to resume in fiscal year 2008.

It is important to note several important gaps in the data below. Utility customer service conservation expenditures are included. However, little or no savings are reflected for utility customer service conservation activities. This is because many of these services do not lend themselves to tracking and verifying the savings. Also, low-income weatherization services are provided through Public Benefits funds. Low-income weatherization services are just one component of services provided to low-income households to assist them in meeting their critical energy needs in a safe manner. Because of this unique focus, expenditures and savings for this program are not comparable to expenditures and savings for other conservation and energy efficiency services and have not been included in the figures below. Based on DOA statistics, about $31.5 million was spent on low-income weatherization in calendar year 2004 and about $40 million is scheduled to be spent on low-income weatherization in calendar year 2005. These expenditures include both natural gas and electric expenditures.

In addition to the electric energy efficiency savings reflected in the data below, natural gas savings have and will continue to occur. Total natural gas energy efficiency expenditures by the utilities and DOA were about $20 million in 2005. With the exception of a temporary increase to about $24 million in 2006, natural gas energy efficiency expenditures are expected to remain at roughly the same level through 2012. Annual therm savings are expected to be between 11 and 15 million for the years 2005 through 2012.

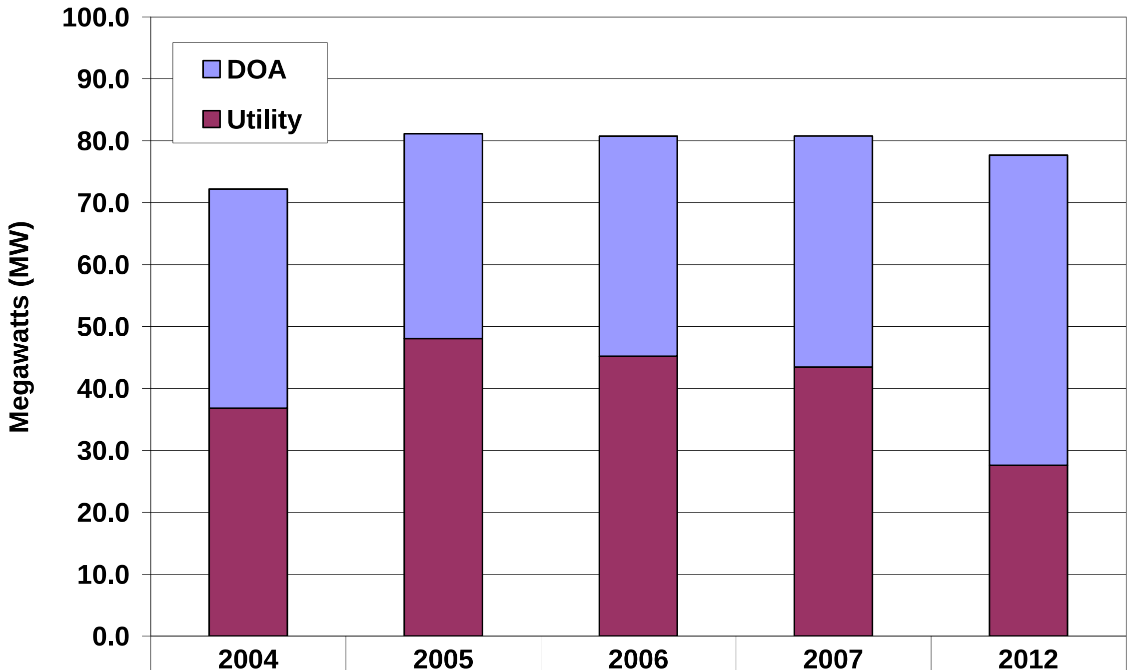
[7] Although electric cooperatives and municipal utilities that are not members of DPC or WPPI also provide conservation and energy efficiency services, their costs and savings are not included. Not all of these electric cooperatives and municipal utilities track achievement of energy and demand savings. Total spending of these utilities are less than 1 percent of the total expenditures of the utilities included in the figures. Because of the relative size of the electric cooperatives and municipal utilities, this omission does not greatly affect the aggregate totals.

Figure 5-01 Annual Electric Energy Efficiency Expenditures



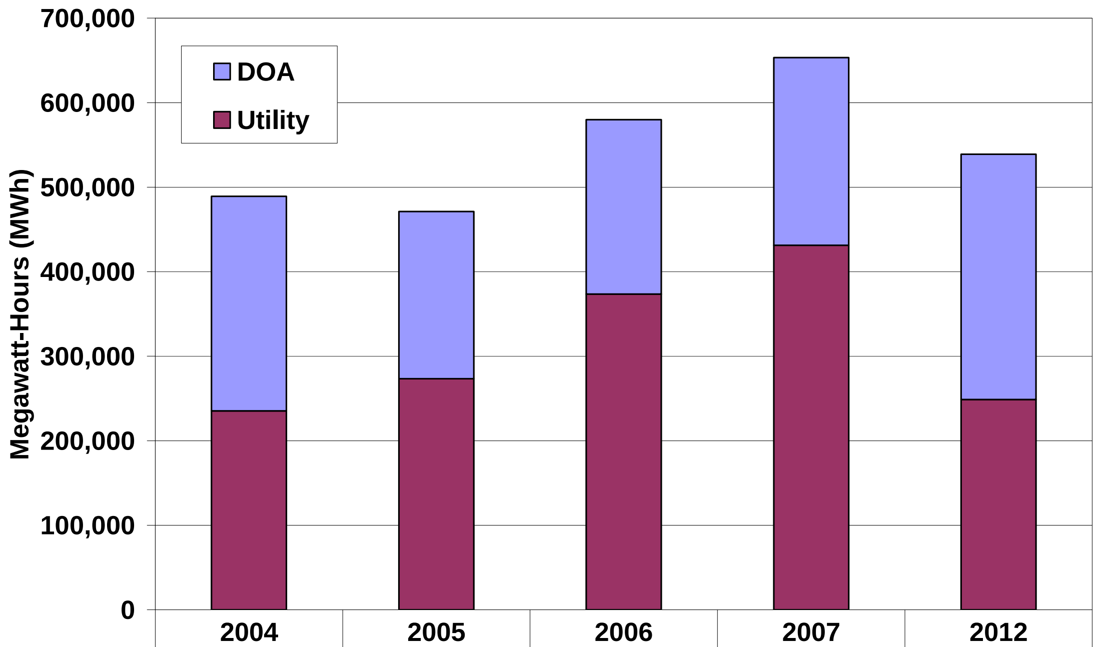
	2004	2005	2006	2007	2012
DOA	$24,584,573	$24,278,472	$29,948,238	$34,563,182	$43,348,180
Utility	$29,295,453	$31,589,803	$43,336,929	$43,561,789	$29,942,785

Figure 5-02 Demand Savings, MW



	2004	2005	2006	2007	2012
DOA	35.4	33.1	35.6	37.4	50.1
Utility	36.8	48.1	45.2	43.4	27.6

Figure 5-03 Annual Electric Energy Savings, MWh



	2004	2005	2006	2007	2012
DOA	254,167	197,822	206,260	222,120	290,229
Utility	235,185	273,456	373,611	431,208	248,736

Renewable Resources

Generation of Electricity from Renewable Resources

The generation of electricity from renewable sources is expected to increase steadily during the planning period. This growth will come from three areas – onsite customer generation, green pricing programs, and utility efforts to comply with the renewable portfolio standard (RPS). In 2004, about 2,290,232 MWh or 3.44 percent of all electrical energy sold in Wisconsin was generated from renewable resources.

Currently, Wis. Stat. § 196.378 requires all retail electric providers to provide a minimum portion of their total retail sales from renewable resources. It establishes a baseline based on each provider's renewable percentage for 2001, 2002, and 2003. By 2010, each electric provider must increase its renewable percentage by 2 percent, and by 2015 by 6 percent. The overall state goal is that by December 31, 2015, 10 percent of all electric energy consumed in the state will come from renewable resources.

Customer-Sited Renewable Generation

A small portion, approximately 4.5 percent, of the Public Benefits Fund goes to the FOE Renewable Energy Program operated by Wisconsin Renewable Energy Network. For the calendar year 2005, the FOE renewable energy program had a budget of $2,305,266 and for 2006 its budget is $2,128,608. Customer-sited technologies covered by the FOE program include:

- Photovoltaic or solar electric;

- Small-scale wind;
- Biomass;
- Heat pumps; and
- Solar water and space heating.

Incentives to encourage greater use of these renewable technologies by utility customers include cash back awards, implementation grants, business and marketing grants, demonstration grants, feasibility grants, and technical assistance.

For fiscal year 2005, energy savings produced by the FOE renewable energy program were determined to be 20.8 million kWh and 900,000 therms with an annual monetary value of $2.9 million.

Hydropower

Small hydropower plants exist along the Wisconsin River, Chippewa River, Flambeau River, and the Wolf River. For the years 2001-2003 Wisconsin's 500 MW of hydro capacity produced an average of 2,180,700 MWh of electricity. Annual hydro production is highly dependent of average rainfall and can vary from year to year by as much as 25 percent. There is little potential for increasing the capacity of this renewable resource, aside from the upgrading of existing facilities and refurbishing of a number of small, recently retired units.

Wind

There are currently 53 MW of wind power capacity in Wisconsin and an additional 884 MW under development. MGE operates 11.2 MW of capacity in the towns of Lincoln and Red River in Kewaunee County. WPSC has 9.2 MW of wind in the town of Lincoln and owns the 1.2 MW Zirbel project in the town of Glenmore, Brown County. WEPCO operates two 660 kW turbines at Bryon in Fond du Lac County. In 2001, Badger Windpower, LLC brought online a 30 MW wind farm east of Montfort in Iowa County.

Wisconsin electric utilities and IPPs have proposed 15 new wind power projects for construction in the next few years. On July 14, 2005, the Commission granted a CPCN to Forward Energy LLC (Forward), owned by Invenergy Wind LLC, to build a 200 MW wind project in Dodge and Fond du Lac Counties. Power from the Forward project is under contract to go to WP&L, WPSC, MG&E, and WPPI. We Energies plans to develop 160 MW of new wind capacity in addition to purchasing the production of a 54 MW project in Dodge County.

The federal production tax credit (PTC) plays a major role in the economics of wind power projects. The PTC, currently 1.9 cents per kWh, is available for 10 years to renewable energy projects that go online before December 31, 2007.

The environmental effects of wind energy are mostly positive, but there are also some potentially negative impacts. The environmental benefits derive from the fact that using wind to generate electricity produces no carbon dioxide (CO_2), SO_2, NO_X, particulate matter or other air emissions. Environmental and other concerns associated with wind power include, aesthetics, sound, bird and bat interactions, and land use impacts. These issues must be taken into consideration when siting wind energy facilities.

Biomass

At the present time, the largest category of non-hydro renewable resources is biomass. This category includes wood, wood and paper waste, herbaceous plants, plant products, and biogas from landfills, wastewater treatment, and on-farm anaerobic digestion of manure. Xcel burns wood fuel at Bayfront 4 in Ashland (36 MW) and at French Island (31.3 MW). The Minergy, LLC facility, located in Neenah, has 6.5 MW of biomass capacity. Landfill gas projects provide a total of 39.2 MW of capacity and more and more large animal operations are using anaerobic digestion of manure to generate electricity.

Solar

PSC records show 21 utility-owned photovoltaic (PV) or solar electric facilities in Wisconsin with a total capacity of 82.2 kW. However, the most appropriate and cost effective application of a PV system is for onsite generation. Several factors will increase the number of PV systems in the next few years. Those factors include increasing fossil fuel prices, rising electric rates, federal tax credits, Focus on Energy incentives and electric buy back rates such as the 22.5 cents per kW offered by We Energies.

PUBLIC HEALTH AND SAFETY AND ENVIRONMENTAL PROTECTION

Generation Overview

The production of electricity affects the environment, communities, and public health. Producing electricity creates wastes and uses limited resources such as land and water. Different power plant technologies and fuels used to fulfill the state's energy demand produces tradeoffs between public health and environmental impacts versus need and cost. While there are often economies of scale for larger generation plants, it causes more concentrated impacts to nearby communities. Another consequence of maintaining fewer but larger power generation plants is the need for more transmission lines which can result in other environmental impacts.

Types of Generation

More than 60 percent of electricity used in Wisconsin is generated by the burning of coal, and approximately 8 percent of total generation is from less efficient, more polluting older coal units, those built before 1960. Slightly less than 17 percent of the electrical energy consumed in Wisconsin is supplied by nuclear facilities. Natural gas is used to generate less than 3 percent of the electricity produced in Wisconsin while renewables account for less than 1 percent. On a percentage basis, Wisconsin relies more on coal-fired generation as an electric energy source than Minnesota, Illinois, or the U.S. in total.

Clean Coal Study Group

As a part of Conserve Wisconsin, Governor Doyle has asked the Commission and DNR to investigate IGCC technology and its potential for the future energy needs of Wisconsin.

IGCC converts coal into gas. The gas is cleaned and then burned in a combined-cycle gas turbine power plant. IGCC dramatically reduces air emissions, water use and industrial waste, but there are unanswered questions about the technology's reliability and cost. The Clean Coal Study Group was created to analyze the technology and answer the questions about reliability and cost. With the leadership of PSC Commissioner Mark Meyer and DNR Air and Waste Administrator Al Shea, the study group members include environmental organizations, customer and labor groups, research institutions and electricity providers. The group has been meeting monthly to hear from experts including the Electric Power Research Institute (EPRI), gasification vendors, project developers and environmental analysts. The group also traveled to Terre Haute, Indiana early this year to tour an IGCC facility, one of two commercial operations in the U.S. The group will provide Governor Doyle with a summary of its investigation later this year.

General Types of Pollutants

One of the major sources of air pollution in the state is electric generation facilities. Table 7-01 shows which pollutants power plants emit and which pollutants other industries and vehicles emit.

Table 7-01 Major Sources of Air Pollutants

Pollutant	Power Plants	Vehicles	Industry
Carbon Dioxide	X	X	-
Carbon Monoxide	-	X	X
Volatile Organic Compounds	-	X	X
Nitrogen Oxides	X	X	Some
Particulate Matter	X	X	X
Sulfur Oxides	X	-	-
Mercury*	X	-	X

* Industry emits some mercury from industrial coal combustion. Industrial emissions of mercury are significant when atmospheric releases of mercury from non combustion activities are included.

Efficiency is one means of reducing environmental impacts. As different generation technologies reach higher efficiency levels, fewer pollutants are potentially released for every unit of fuel consumed. This is especially relevant to the use of fossil fuels that causes the majority of the state's air pollution (Table 7-02).

Table 7-02 General Efficiency of Power Plants

Plant Operation	Approximate Efficiency
Coal Plants	
Traditional	30-35%
Super-Critical Pulverized Coal (SCPC)	42%
Integrated Gasification Combined-Cycle (IGCC)	42-46%
Cogeneration*	40–50%
Natural Gas Plants	
Older Combustion Turbines (CT)	26%
Newer Combustion Turbines (CT)	36%
Combined-Cycle (CC)	50-55%
Cogeneration *	60-70%
Fuel Oil	
Internal Combustion Engines	35%

* All power plants produce electricity. Cogeneration plants produce electricity and steam.

There is a definite trend towards improving the technology for both coal and natural gas fuels to afford higher levels of efficiency.

Comparing the pollutants emitted from a sampling of Wisconsin plants based on the type of plant and type of fuel shows that the use of the latest pollutant control methods can produce a significant reduction in the pollutants emitted. For the four pollutants CO_2, particulate matter less than 10 microns in diameter (PM_{10}), NO_X, and sulfur oxides (SO_X), combined-cycle natural gas-burning plants produce the lowest level of pollutants per MWh of electricity generated. In comparison to other types of natural gas-burning generation, newer CT plants produce the next lowest, followed by older CT plants. Similarly, super-critical pulverized coal (SCPC) coal burning plants produce fewer emissions than older technology coal plants, especially SO_X and NO_X pollutants. Whereas, fuel oil burning internal combustion engines can produce as much or more CO_2, PM_{10}, NO_X, and SO_X pollutants as some coal-burning plants.

Health and Environmental Impacts

Fuel efficiency and increasingly advanced control technologies for Wisconsin's power plants is important in reducing their emissions of pollutants. The general health and environmental impacts caused by these pollutants are listed in Table 7-03.

Table 7-03 Health and Environmental Impacts from Pollutants Emitted by Electric Generation Facilities

Pollutant	Impacts	Regulated
Carbon Dioxide	Environmental Impacts – a greenhouse gas that contributes to global warming	-
Carbon Monoxide	Health Impacts – heart strain	X
Particulate Matter (PM_{10} and $PM_{2.5}$)	Environmental Impacts – haze, smog, can damage plants Health Impacts – lung damage, asthma bronchitis, pneumonia Property Damage – can dirty and discolor structures, clothes, and furniture	X
Volatile Organic Compounds	Environmental Impacts – smog, contributes to elevated ozone levels, and can damage plants Health Impacts – lung damage, asthma bronchitis, pneumonia	X
Nitrogen Oxides	Environmental Impacts - acid rain, smog, contributes to elevated particulate levels, N_2O is a greenhouse gas Health Impacts – lung damage, asthma, bronchitis, pneumonia	X
Sulfur Oxides	Environmental Impacts - acid rain, contributes to elevated particulate levels, harmful to plants Health Impacts - lung damage, asthma, bronchitis, pneumonia Property Damage – can deteriorate fabrics, corrode metals, damage and stain stone structures	Only SO_2
Mercury	Environmental Impacts – bioaccumulation of mercury in wildlife Health Impacts – consumption of fish with elevated mercury levels can cause damage to nervous systems, especially in children and fetuses	X

Transmission Overview

Utilities are investing in the rebuilding and upgrade of aging transmission and distribution lines. This increases the adequacy, reliability, and safety of these lines. In addition, utilities are adding distribution substations to serve growing local use of electricity. These new distribution substations and the new transmission lines that serve them will greatly increase reliability. The primary reason for new transmission and distribution facilities is to provide adequate voltage to customers and not damage other utility or customer equipment when contingencies occur. The most common contingencies are tree, animal, and vehicle contacts; storms; and electrical system component failure. When these incidents occur, system protective devices quickly isolate the incident and minimize the size of the outage and any further damage.

Transmission projects that require new ROW are identified in Table A-03 and will need to avoid or mitigate impacts to a number of sensitive and cultural resources. Input from resource experts, communities, property owners, and the public will be necessary to properly site these new transmission corridors.

Federal and State Regulations

The following changes to the federal and state regulations will impact generation and transmission utility operations in the state of Wisconsin. These regulations regarding environmental issues are currently in a state of flux, and need to be tracked and analyzed by utility personnel, regulators and the public on an ongoing basis.

- Federal Energy Policy Act of 2005 – encourages the construction of renewable and lower polluting electric generation technologies and the installation of air pollution control facilities; contains the establishment of "national interest transmission corridors" and other transmission siting provisions
- Clean Air Mercury Rule (CAMR) – establishes federal caps on mercury emissions for coal-fired generators and a cap-and-trade program
- National Ambient Air Quality Standards –proposed revisions to the EPA fine particulate matter ($PM_{2.5}$) standards
- Clean Air Interstate Rule (CAIR) – establishes federal caps on combined power plant emissions of sulfur dioxide and nitrogen oxide and sets up a cap-and-trade program for the two pollutants
- Wisconsin Shared Revenue Program – provides monetary incentives to local communities for new power plant construction
- Wisconsin Act 141 – Revises the funding and structure of energy efficiency and renewable resource programs in the state of Wisconsin
- Wisconsin Act 89 – establishes a pre-application process for choosing transmission route alternatives and prioritizes the use of existing corridors for transmission siting
- Wisconsin Act 24 – provides for the necessary easements of municipal and county lands for transmission projects
- High-Voltage Transmission Line Impact Fees – provides monetary incentives to local communities for new high-voltage transmission construction

Public Involvement

Public involvement in the review of transmission and generation projects is an important part of the Commission review process. The Commission regularly facilitates public meetings on transmission line siting and new generation. At these meetings the public is sought out to provide issues of concern. Through the Commission's ERF system, all applications and documents can now be routinely viewed by any member of the public with internet access. In addition, individuals can subscribe for a particular construction project docket and receive automatic e-mails when new documents are uploaded onto the system, without the delay of a traditional paper system.

RATE AND COST TRENDS

Table 8-04 summarizes the regulatory structures that currently exist in the Midwest. The table identifies both the regulated-rate states and the retail-choice states. The table illustrates that the ability to make rate comparisons between these states is not straightforward. The comparison to Wisconsin rates in some cases is often an apples to oranges exercise as bankruptcy and financial instability is a risk that the Wisconsin regulatory approach does not create.

Some specific examples of state to state differences follow:

- Among regulatory structures, there are states with vertically integrated utilities and some with stand-alone transmission companies, like in Wisconsin.
- Some states have one-for-one fuel cost pass through, while some do not.
- Some states, as part of retail restructuring, have given providers the option of foregoing fuel cost recovery. Illinois was one of those states.
- In some cases legislatively enacted rate reductions and freezes are soon to expire; some have already expired. The consequence is that other states will be entering periods of rate increases that have not yet shown up in the national data that has been used to compile Figures 8-01 through 8-03 and Tables 8-01 through 8-03. For instance, beginning in 2006, Detroit Edison's electricity rates will be increasing 23 percent for the first time in 13 years.[8]
- In Ohio, a competitive auction to provide power and energy to First Energy was deemed faulty by the Ohio Public Utilities Commission (Ohio PUC) due to high prices and the lack of competitors.[9]
- In Illinois, where large rate increases are imminent, there is some likelihood that the state's major electric providers could file for bankruptcy if the move to market based rates does not occur. Ameren Illinois has estimated that the necessary average rate increase could approach 35 percent.[10]
- The Ohio PUC has granted First Energy deferrals for increases in fuel costs for the 2006 to 2008 time period that will not be collected from ratepayers and will not affect rates until some time in 2012.[11]
- In 1997-1998, when natural gas prices were not expected to significantly increase, CE opted for a freeze on any fuel cost recovery changes with the expectation that lower or stable natural gas fuel costs would increase its profitability. In hindsight that assumption was wrong; but the company's parent holding company still was able to make record profits because it sold its former coal baseload plants at a premium and was able to keep the profits above book value and not return such profits to ratepayers. Any excess power CE subsequently had was sold into the wholesale market by a deregulated arm at much higher market prices established by the higher cost of natural gas. The same is true for the entities that bought the baseload coal plants from CE. In an

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[8] "Budget Busters: Gas, Heat, Electricity," The Detroit News, December 22, 2005.

[9] 2005 End of Year Review, Public Utility Commission of Ohio, at www.puco.ohio.gov.

[10] "Ameren Corp. Illinois Customers May See Electric Bills Rise," St. Louis Post-Dispatch, September 30, 2005, at www.energycentral.com.

[11] 2005 End of Year Review, Public Utility Commission of Ohio, at www.puco.ohio.gov.

environment like this, power purchased from wholesale markets by Wisconsin providers has been expensive.

- RTOs create seams and additional transmission tariffs that do not foster the most cost efficient exchange of electric power. For instance, CE is in the PJM RTO; yet, CE borders Wisconsin. Under the rules and tariffs of PJM, CE can make more profit selling its energy to the east coast market than to Wisconsin providers. This issue was created by the FERC allowing CE to join PJM. The Wisconsin Commission is vigorously intervening at the FERC and MISO to have mechanisms in place that hold Wisconsin ratepayers harmless from such actions.

- To date, some of the cheaper power that could have been available to Wisconsin, had appropriate RTO rules been in place, was not. This too has led to increases in Wisconsin's purchased power costs.

For all of these reasons extreme care should be used when making rate comparisons across states. A more appropriate examination might require review of rates over a ten or twenty year period as the vagaries of the alternative regulatory structures work themselves out.

Changes in the ownership of the transmission system and of generation plants, construction and timing of new utility generation plant, fuel costs, the emergence of the MISO Day 2 Market for power have had, or will have a profound impact on the rates Wisconsin customers pay. How these costs are handled differently in other states when establishing rates will influence the competitive position of rates between Wisconsin and these other states.

That said, in 2000, electric ratepayers in Wisconsin were paying lower bills than most of the eight Midwest states and other United States, according to data collected from the U.S. Energy Information Administration (EIA). In 2000, residential, commercial, and industrial customers all paid a lower than average rate for electricity than the eight Midwest states and were below the United States average rate as well. However, by 2005, retail Wisconsin residential rates were higher than the other Midwest states. Industrial Wisconsin rates have also increased, and are now above the Midwest average and approach the U.S. average. Wisconsin retail commercial rates also increased, but not as rapidly as residential and industrial rates. These changes are shown on Tables 8-01 through 8-03. Wisconsin commercial and industrial rates are still below national averages. Recent rate and fuel increases in Wisconsin have been driven by factors outside of the Commission's control. Fuel price and purchased power cost increases have constituted about 65 percent of the increases, and new power plant construction to maintain reliability has contributed approximately 25 percent. See Figure 8-01.

Figure 8-01 Actual Electric Rate Increases in 2005 - Significant Factors that Increased Electric Rates

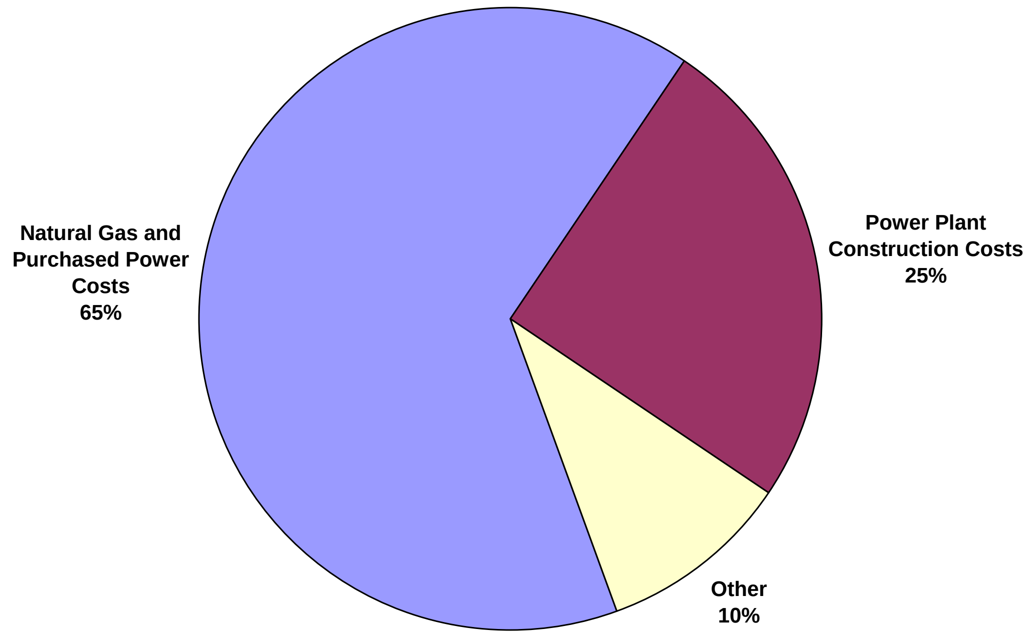

Table 8-01 Residential Average Rates in the Midwest and U.S.

	2000	2001	2002	2003	2004	2005
Illinois	8.83	8.70	8.40	8.38	8.37	8.34
Indiana	6.87	6.90	6.90	7.04	7.30	7.49
Iowa	8.37	8.40	8.30	8.57	8.96	9.36
Michigan	8.53	8.40	8.50	8.35	8.33	8.60
Minnesota	7.52	7.60	7.50	7.65	7.92	8.34
Missouri	7.04	7.00	7.10	6.96	6.97	7.08
Ohio	8.61	8.30	8.10	8.27	8.45	8.50
Wisconsin	7.53	7.90	8.10	8.67	9.07	9.64
Midwest Average	**7.97**	**7.90**	**7.83**	**7.89**	**8.17**	**8.42**
U.S. Average	**8.21**	**8.57**	**8.43**	**8.70**	**8.97**	**9.42**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Table 8-02 Commercial Average Rates in the Midwest and U.S.

	2000	2001	2002	2003	2004	2005
Illinois	7.53	7.40	8.30	7.22	7.54	8.05
Indiana	5.93	5.80	6.00	6.13	6.31	6.54
Iowa	6.57	6.70	6.60	6.24	6.75	6.95
Michigan	7.90	7.60	7.50	7.55	7.57	8.09
Minnesota	6.36	6.00	5.90	6.12	6.31	6.56
Missouri	5.83	5.90	5.90	5.78	5.80	5.88
Ohio	7.61	7.90	7.70	7.60	7.75	7.92
Wisconsin	6.03	6.40	6.50	6.97	7.24	7.61
Midwest Average	**6.82**	**6.76**	**6.84**	**6.66**	**6.91**	**7.20**
U.S. Average	**7.36**	**7.91**	**7.93**	**7.98**	**8.16**	**8.68**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Table 8-03 Industrial Average Rates in the Midwest and United States

	2000	2001	2002	2003	2004	2005
Illinois	4.76	4.80	5.60	4.91	4.65	4.52
Indiana	3.81	4.00	4.00	3.92	4.13	4.40
Iowa	3.89	4.20	4.00	4.16	4.33	4.57
Michigan	5.10	5.20	4.90	4.96	4.92	5.58
Minnesota	4.57	4.60	4.20	4.36	4.63	5.06
Missouri	4.43	4.50	4.50	4.49	4.62	4.59
Ohio	4.47	4.70	4.70	4.79	4.89	5.03
Wisconsin	4.04	4.30	4.40	4.71	4.93	5.33
Midwest Average	**4.43**	**4.57**	**4.56**	**4.51**	**4.64**	**4.89**
U.S. Average	**4.57**	**5.07**	**4.84**	**5.13**	**5.27**	**5.57**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Table 8-04 Regulatory Structures Currently in the Midwest

	Minnesota	Iowa	Wisconsin	Illinois	Michigan	Indiana	Ohio	Missouri
Retail Rates	PUC Regulated	IUB Regulated	PSC Regulated	Choice, legislative 5-15% rate reduction and freeze to 2006. Market based rates 2007.	Choice, legislative freeze ends 2005.	Limited choice, mostly IURC regulated.	Choice. Legislative rate freeze thru market development period 2000-2005. Rate stabilization plans until 2008.	PSC Regulated
IRP Planning	Yes	No	No	No	No	No	No	No
Transmission Structure	VITO	VITO	LSE, Independent	VITO	LSE, Independent	VITO	VITO	VITO
Regional Transmission Organization	MISO	MISO	MISO	PJM & MISO	MISO	MISO	PJM & MISO	MISO & SPP
Fuel Pass Through Treatment	Fuel adjustment clause, no dead band.	IPC automatic fuel clause; MidAmerican operates with freeze.	Fuel rules treatment; rate orders set dead band.	CE and Ameren have opted out of automatic fuel clause adjustment.	Automatic fuel adjustment; shareholders are not at risk. Hearingrtequired.	Fuel clause is automatic. No shareholder risk.	No automatic pass through. Fuel rate freeze 2000 to 2005.	NA
Important Retail Choice Rate Developments				Ameren indicates up to 35% rate increase likely by 2008. CE and Ameren threaten bankruptcy if not allowed to pass on market based energy prices.	Beginning 2006 residential rates for Detroit Edison customers will increase 23%. Consumers Energy residential rates will increase 10%.		Rate shock upon move to market based rates and lack of competition lead state to implement rate stabilization plans. AEP's Ohio Power gets rate increases of between 7-11% each year 2006-2008. All fuel increases for 2005-2008 for First Energy are deferre	

VITO = vertically integrated utilities with both generation and transmission ownership
LSE = load serving entity or utility with only generation and distribution lines
Independent = independent transmission company
Choice = some form of retail competition; form varies by state, usually for industrial and commercial customers
SPP-Southwest Power Pool, MISO-Midwest Independent Transmission System Operator, PJM-PJM LLC.

TOPICAL QUESTIONS TO AID COMMISSION POLICY DIRECTION

Topical questions were put forth by the Commission during the initial data gathering phase of this SEA. Topics include policy challenges, rates, integration of generation and transmission, environmental regulations, the Federal Energy Policy Act of 2005, and natural gas pipeline expansion. Summarized in Appendix B are the responses received by the Commission. Other interested participants are invited to submit comments to these questions by participating in the public hearing expected to be held later this year.

FUTURE CHALLENGES

In the near future, the Commission will address a number of policy issues that will affect the reliability of the bulk power system in Wisconsin and the level of retail electric rates charged to Wisconsin ratepayers. Policy decisions on several of these issues will be made directly by the Commission, while Commission policy on others will be dependent upon regulatory policies adopted by FERC, the North American Electric

Reliability Organization (NAERO) and MISO. A summary of these policy issues includes:

Framework for Generation, Transmission, and Energy Efficiency/Renewables Integration

Stakeholder comments in this SEA agree that a better form of transmission, generation and conservation integration is necessary in Wisconsin. There is no consensus on how to do such integration. As bookends there are two models: a completely trust-the-market approach versus a proscriptive, detailed, contested-case centralized planning process. Neither is suitable for the reality that faces Wisconsin. But, a hybrid approach that is multidimensional involving significant input from stakeholders and the Commission could fit the current electric industry structure.

A hybrid approach that adjusts present information gathering, review, and decision-making to reflect the increasingly regional and market-oriented nature of the procurement and delivery of electricity would aid the Commission and all stakeholders. A way to accomplish this is to have new, non-periodic Commission investigations (the Commission's response to ATC's Access Study Initiative serves as a model) that include Commission staff and stakeholder participation. In addition, it will be necessary to continue to participate in existing state, regional and national energy processes. Sample activities that could be considered are:

- **Modify SEA process.** Expand the SEA planning horizon to 10 years if MISO and reliability organizations adopt a 10-year planning standard. Require ATC and Wisconsin's electric utility providers to submit information (for review, not approval) showing that their approaches do not place undue cost or risk on ratepayers.

- **Contested topical cases.** These proceedings could facilitate full stakeholder participation for evolving issues that need to be addressed by the Commission as energy regulatory policy is set. It is not expected that these topical cases would be numerous. Subject matters could include energy efficiency programs; demand and price response tariffs; multi-state transmission collaboratives; reserve criteria review; renewable portfolio compliance; others.

- **Investigations (non-contested).** Investigate special situations that are infrequent, such as: reliability events; technology shifts; emissions strategies; policy approaches; others. A recent example is the Commission's response to ATC's Access Study Initiative docket.

- **Rulemaking.** The 2005 Wisconsin Act 141 Energy and Efficiency Renewables Act is an example where the Commission will establish rules. Although Act 141 already requires periodic reporting, a result could be to require the Commission to evaluate energy efficiency and renewables programs on a set, periodic basis (for example, every four years). The Commission will also be required to set or revise goals, priorities and measurable targets.

MISO Activities

Many of the suggestions made late last summer by industry participants are turning into reality. Pricing information is being posted in detail. The MTEP06 scope of work includes exploratory studies, reliability assessments, and the review for regional economically beneficial projects. There is also discussion about expanding MTEP's modeling years farther into the future. The Commission is actively participating in the MISO and the Organization of MISO States (OMS) committees and work groups. The Commission is also monitoring these developments at the FERC level along with supplying comments. The EPAct05 has also set into motion new activities to explore the more efficient and reliable use of the power network on a much larger scale than one state. It also suggested that regional advisory bodies could be set up between states to coordinate their respective long-term goals. The EPAct05 also appears to preserve states' rights to fulfill resource adequacy compliance. Although the final set of functions and activities have not been detailed at the time of this writing, it will likely be a coordinated set of guidelines, standards, business rules, and activities delineated between FERC, the RTOs, the NAERO, the regional reliability councils, and the states.

Responses to Topical Question 4, which asked about MISO's wholesale power market and associated costs and benefits, indicate that it was very difficult or impossible to quantify the costs and benefits of the MISO market. The responses indicate that utility experiences were very different with certain aspects of the new market. Virtually all respondents have significant concerns about MISO administrative costs and with the financial settlement process.

Transmission

On February 14, 2005, the Commission opened docket 137-EI-100 as a generic investigation into ATC's Access Study Initiative. This docket began as a result of the 2004 SEA, in which the Commission requested comments on what the appropriate amount of transfer capability should be for Wisconsin. At the Commission's direction, ATC filed an updated Access Study Initiative report, which included five representative EHV transmission projects for increasing import capability and one lower voltage alternative. The EHV projects were between 35 and 275 miles long, with construction costs between $66 million and $621 million. Commission staff filed a draft report on the Access Study Initiative in November 2005, and stakeholders were given the opportunity to comment on both filings. On February 8, 2006, the Commission held an open meeting at which ATC, stakeholders, and other members of the public were invited to speak and answer questions from the Commission. On February 28, 2006, the Commission discussed its observations and conclusions. On March 23, 2006, the Commission concluded the docket and released the Commission staff's final report.

Key observations include:

- ATC and stakeholders concluded that targeting a specific transfer capability value was inappropriate because EHV lines can be used for a variety of system purposes. Consequently, the focus of this docket turned toward the broad policy issues surrounding transmission planning.

- The analysis in the Access Study Initiative was preliminary, but it did suggest that, under certain circumstances, Wisconsin ratepayers could benefit from expanded interstate transmission investment, particularly from investment that is targeted to smaller scale projects.

- With respect to the five EHV alternatives and the one lower voltage option presented in the Access Study Initiative, there was insufficient information to make an informed choice or even select a short list as ATC has requested.

- Assuring that Wisconsin ratepayers benefit from expanded interstate transmission investment requires a rigorous, thorough quantitative and qualitative analysis. That analysis should also include a detailed risk assessment so that matters of professional judgment can be clearly identified and investigated by the Commission.

- New ENV projects should adhere to the principle of protecting the ratepayer from unjust or unreasonable costs or risks.

- EHV applicants should demonstrate significant regional cooperation, planning and public input before applying for a CPCN.

Planning Reserve Margins

The Commission currently requires load serving entities in eastern Wisconsin to maintain an 18 percent planning reserve margin for each upcoming summer season. The 18 percent requirement was adopted by the Commission in Advance Plan 8.[12] NSPW and DPC currently maintain a 15 percent planning reserve which was a requirement of the MAPP reliability council.

It is possible that the planning reserve level in Eastern Wisconsin could be reduced from 18 percent and still meet one day in ten year reliability criterion. This needs further study and input from stakeholders. Determining the appropriate level of planning reserves will be complicated by three factors. First, as mentioned earlier, there has been a realignment of reliability council membership by the Wisconsin utilities. The evaluation of the appropriate level of planning reserves for Wisconsin will need to take into account the reserve sharing rules that MRO and RFC adopt. Secondly, planning reserves act as a price hedging mechanism for market participants in the MISO Day 2 Market. It may be prudent to carry planning reserves in excess of those necessary to meet a reliability target is those reserves provide a hedge against exposure to high costs in the LMP energy market. Finally, MISO is also considering the adoption of resource adequacy requirement for market participants. It is not clear

[12] Findings of Fact, Conclusions of Law and Order, docket 05-EP-8, November 20, 1997.

at this time how any MISO resource adequacy requirement will be harmonized with the reserve requirements adopted by MRO and RFC.

New Energy Efficiency Concepts

One benefit of energy efficiency is the impact it can have on the timing and size of new power plants needed in the future. Energy efficiency has also become an increasingly important tool for customers to reduce their energy bills. The recently passed energy efficiency legislation gives the Commission the responsibility to ensure energy efficiency resources are fully developed. Two steps are needed to ensure that this is accomplished. The Commission plans to fully support and foster energy efficiency efforts in this state. First, the Commission must, generally through rulemaking, establish the necessary procedures for the development and implementation of energy efficiency programs. These include procedures to set appropriate goals, priorities, and measurable targets and procedures for the review, approval, and evaluation of energy efficiency programs. A second step is to determine the resources, in terms of staffing and tools, the Commission needs to accomplish its energy efficiency mandates.

Renewable Energy Ideas

The Commission believes that the new Wisconsin Energy Efficiency and Renewable Energy Act (2005 Wisconsin Act 141) recently passed by the legislature, and signed by the governor, presents an excellent opportunity for utilities and state-owned facilities to showcase new renewable energy applications using solar space and water heating, photovoltaics and small wind generators. Many high schools, UW campuses and vocational colleges are already doing this. All high schools and college campuses in the state should be encouraged to install renewable systems and use them to educate the public as well as their own students. This could be achieved through innovative rate approaches and other service offerings by the utilities. The Commission encourages the state electric utilities to incorporate such service offerings in their rate case applications.

Greater demand for renewable energy systems should encourage the Wisconsin manufacturing sector to become more involved in producing components such as towers, electric generators, gear boxes, and blades for wind turbines and panels, tracking systems and electronic controls for solar systems. The new 10% renewable requirement along with Focus on Energy program will also encourage greater use of anaerobic digestion to fuel electrical generation on farms with large numbers of animals. The Commission will continue to support these renewable efforts.

Mitigating Electric Rate Increases in a Period of Significant Additions to Infrastructure

In Wisconsin, electricity demand from consumers is rising. While this is a positive sign that the economic health of Wisconsin is strong, it has resulted in the need to improve the infrastructure that serves consumers, which in turn puts upward pressure on rates. In addition, the cost of fuel, especially the cost of natural gas, is rising, another significant factor in the present era of rising utility rates. The Commission will be proactive in keeping utility rates as low as reasonably possible, while preserving electric reliability and protecting the public trust. That said, one of the rate policy matters that the Commission is pursuing focuses on making sure price signals are proper when designing rates. This is being done within the generic investigation opened in 2005 regarding electric cost of service studies. In addition, the Commission is analyzing the possible retooling of electric fuel rules in order to provide utilities proper incentives to control electric generation fuel costs, as described later in this report. Also, the Commission is heavily involved in analyzing the performance of the MISO market, especially as it relates to what Wisconsin's electric utility customers ultimately pay for electricity.

For the future, the Commission may explore new rate options that will allow customers to reduce their electric bills. The key to these new rate options will be to provide customers with the appropriate incentives so they have the opportunity to reduce usage during high cost periods and increase usage during low cost periods. Current time-of-day rates have simple on-peak and off-peak pricing periods. These time-of-day rates could be modified to include additional pricing periods so that the rates could more closely track costs. Wisconsin has limited experience with real time pricing. Two utilities offer real time pricing, but only one customer takes service under a real time pricing tariff. Under real time pricing, rates are determined a day in advance for each hour of the succeeding day. Wisconsin has significant experience with interruptible rates. Interruptible rates are primarily used by large industrial customers. New metering and communication technologies may provide an opportunity for smaller customers to take advantage of real time pricing and interruptible rates. The MISO Day 2 Market provides hourly LMPs that could be used as the basis for new time-of-day, interruptible and real time pricing rate options.

The Commission is always performing ongoing analysis of its own regulatory processes as it relates to ratemaking, making sure that the regulatory impact on utility ratepayers and the utilities themselves is positive. Rate case procedures within the Commission itself will always have the ability to change, in order to complement the changing marketplace and regulatory environment.

Ratemaking for Electric Generation Fuel Costs

Prior to April 1, 2005, each large integrated electric utility in Wisconsin dispatched their own generation and scheduled purchases on a daily basis to meet their own load. On April 1, 2005, MISO instituted the operation of a bid-based security-constrained energy market in the MISO footprint. This energy market, along with the associated market rules, is known as the MISO Day 2 Market. In addition, portions of northern Illinois are part of PJM, which operates a similar Day 2 Market. The PJM market affects Wisconsin utilities because they must participate in it in order to schedule energy from purchased power contracts based on generating resources located in Northern Illinois.

The MISO Day 2 Market (and the PJM market) resulted in new streams of revenues and costs for Wisconsin utilities. The interaction of the MISO Day 2 costs and revenues with the fuel rules, and previous deferrals and escrows granted by the Commission in various proceedings, involve complex accounting and ratemaking issues.[13] The Commission staff has been working with the large investor-owned utilities since January 2004 on the accounting and ratemaking issues related to the MISO Day 2 Market with the objective of developing a long-term policy for rate treatment of the Day 2 costs and revenues.

The Commission will adopt policies to properly classify these costs and revenues and determine which costs and revenues should be reflected in base rates, and which should be treated as monitored costs under the "fuel rules."[14] This distinction is important because rates can be adjusted between base rate cases for changes in the cost of "fuel," whereas changes in other costs cannot be reflected in rates without a base rate proceeding. The Commission has opened a docket to analyze these complex issues.[15]

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[13] In addition to deferrals related to MISO Day 2 costs and revenues, the Commission previously granted MGE, WEPCO, WP&L, and WPSC a five-year escrow for certain costs associated with the start-up and operation of ATC in an order issued on October 23, 2002, in docket 05-EI-129. This escrow expired on December 31, 2005. When MISO began operations, it assumed certain functions from ATC. Commission staff has interpreted the so-called "ATC deferral" to include the costs of these functions which are now billed by MISO.

[14] The fuel rules are specified in Wis. Admin. Code PSC ch. 116.

[15] Docket 9300-EI-100.

ACRONYMS

§	Section
Act 9	1999 Wisconsin Act 9
AFUDC	Allowance Funds Used During Construction
ATC	American Transmission Company LLC
Btu	British thermal units
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CC	Combined-cycle
CE	Commonwealth Edison Company
Commission	Public Service Commission of Wisconsin
CO	Carbon monoxide
CO_2	Carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
CT	Combustion turbine
DEK	Dominion Energy Kewaunee
DNR	Department of Natural Resources
DOA	Department of Administration
DOE	U.S. Department of Energy
DOT	Department of Transportation
DPC	Dairyland Power Cooperative
ECAR	East Central Area Reliability Coordination Agreement
ECW	Energy Center of Wisconsin
EHV	Extra High Voltage
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERF	Electronic Regulatory Filing
FERC	Federal Energy Regulatory Commission
FOE	Focus on Energy
Forward	Forward Energy LLC
FTR	Financial transmission rights
GW	Gigawatt
GWh	Gigawatt hour
HVAC	Heating/ventilating/air conditioning
ICF	ICF Resources, LLC
IGCC	Integrated gasification combined-cycle
IPP	Independent power producers
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LIHEAP	Low Income Home Energy Assistance Program
LMP	Locational marginal pricing
MACT	Maximum achievable control technology
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MGE	Madison Gas and Electric Company
MISO	Midwest Independent Transmission System Operator
mmBtu	Million British thermal units
MTEP05	MISO Transmission Expansion Plan 2005

MTEP06	MISO Transmission Expansion Plan 2006
MPU	Manitowoc Public Utility
MRO	Midwest Reliability Organization
MW	Megawatt
MWh	Megawatt hour
NAERO	North American Electric Reliability Organization
NERC	North American Electric Reliability Council
NO_2	Nitric oxide
NO_X	Nitrogen oxides
NSPW	Northern States Power-Wisconsin
Ohio PUC	Ohio Public Utilities Commission
OMS	Organization of MISO States
PJM	PJM Regional Transmission Organization
PM	Particulate matter
PM_{10}	Particulate matter less than 10 microns in diameter
PM_{25}	Particulate matter less than 25 microns in diameter
PSC	Public Service Commission of Wisconsin
PTC	Production tax credit
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policy Act of 1978
PV	Photovoltaic
RFC	Reliability*First* Corporation
ROW	Right-of-way
RTO	Regional Transmission Organization
RPS	Renewable portfolio standard
SCPC	Super-critical pulverized coal
SEA	Strategic Energy Assessment Report
SERC	Southeast Reliability Council
SO_2	Sulfur dioxide
SO_X	Sulfur oxides
SWL&P	Superior Water, Light and Power Company
TVA	Tennessee Valley Authority
U.S.	United States
WEPCO	Wisconsin Electric Power Company
WIEG	Wisconsin Industrial Energy Group
Wis. Admin. Code	Wisconsin Administrative Code
Wis. Stat.	Wisconsin Statutes
WMC	Wisconsin Manufacturers and Commerce
WP&L	Wisconsin Power and Light Company
WPC	Wisconsin Paper Council
WPPI	Wisconsin Public Power, Inc.
WPSC	Wisconsin Public Service Corporation
WUMS	Wisconsin Upper Michigan System
Xcel	Xcel Energy Inc.

GLOSSARY

Capacity	The maximum amount of power that a generating unit can create, usually measured in MW.
Capacity Factor	A calculation, expressed as a percentage such as 70 percent, representing the proportion of time in a year that a generating unit operates at its full electric generating output level.
Demand and Energy Charge	The combined fixed costs for the right to obtain capacity as well as the energy charges that are incurred to produce electricity.
Electric Demand	The amount of instantaneous draw of power from the electric system, usually measured in MW.
Electric Energy	The amount of electricity used over a period of time, measured in MWh.
Energy Charge	The variable costs, including fuel, that are incurred to produce electricity.
Flow Gate	A particular section of the transmission system where energy is monitored for excessive flow.
Focus on Energy Program	Energy efficiency and conservation program administered by the state Department of Administration and funded by the state's electric and gas utilities.
Independent Power Producer (IPP)	A non-utility business that constructs and operates power plants, who sells the electrical output into the marketplace.
Marginal Energy Cost (MEC)	The cost of electric energy for the last unit produced, usually measured in $ per MWh. The MEC is usually comprised of fuel cost, and variable operation and maintenance costs.
Native Load	The amount of electric demand, representing the customers in its service territory that a utility is obligated to serve.
Peak Electric Demand	The amount of instantaneous draw of power from the electric system at the moment of highest use, usually on a hot humid summer day.
Power Purchase Agreement (PPA)	A contract in which an electric generating company sells capacity and energy to a utility.
Therm	A unit used to measure the quantity of heat that equals 100,000 Btu.
Transfer Capability	The amount of electrical output measured in MW that can move over a set of high voltage transmission lines from one area to another.
Sales and Purchases on a Unit Basis	The exchange of electric power and energy from a dedicated generation plant.
Sales and Purchases on a System Basis	The exchange of electric power and energy from a provider's fleet of generation plants.
Simultaneous Transfer Capability	The amount of electrical output measured in MW that can move over all sets of high voltage transmission lines at the same time from one area to another.
With or Without Reserves	A contract specification for an exchange of power and energy in which the seller does or does not provide the additional capacity required so that the sale has the same high level of dispatch priority as native load.

Table A-01 New Utility-Owned or Leased Generation Capacity, 2005-2014

Year	Owner	Project Description	Fuel	Location	Capacity (MW)
2005	WEPCO	Port Washington North Combined Cycle	Natural Gas	City of Port Washington, Ozaukee County	545
2005	WP&L	Sheboygan Combustion Turbines	Natural Gas	Town of Sheboygan Falls, Sheboygan County	300
2005	MGE Power, LLC	West Campus Cogeneration Facility	Natural Gas	City of Madison, Dane County	150
2005	Calpine	Fox Energy Combined Cycle	Natural Gas	City of Kaukauna, Outagamie County	300
2006	Calpine	Fox Energy Combined Cycle	Natural Gas	City of Kaukauna, Outagamie County	240
2006	Manitowoc	Fluidized Bed Boiler	Coke	City of Manitowoc, Manitowoc County	58
2006	Invenergy	Forward Wind	Wind	Towns of Byron, Oakfield, Lomira, and Leroy Dodge and Fond du Lac Counties	200
2006	WEPCO	Wind RFP	Wind	Dodge County	54
2007	WEPCO	Blue Sky / Green Field Wind	Wind	Towns of Calumet and Marshfield, Fond du Lac County	160
2007	WEPCO	Port Washington South Combined Cycle	Natural Gas	City of Port Washington, Ozaukee County	545
2008	WPSC	Weston SCPC Coal Unit 4	Coal	Villages of Rothschild and Kronenwetter, Marathon County	515
2009	WEPCO	Elm Road SCPC Coal Unit 1	Coal	City of Oak Creek, Milwaukee County	615
2010	WEPCO	Elm Road SCPC Coal Unit 2	Coal	City of Oak Creek, Milwaukee County	615
2010	WPPI	Prairie State Energy Campus Coal	Coal	Southern Illinois	50
2011	WEPCO	Point Beach 1 and 2 Nuclear Upgrade	Nuclear	Town of Two Creeks, Kewaunee County	100
				Total Capacity Additions 2005-2011	***4,447***

Table A-02 High-Voltage Transmission Lines 69 kV or Greater and Upgrades/Rebuilds of Lines Greater Than 100 kV – Construction Expected to Begin Prior to December 31, 2012

Endpoint 1 Substation	Endpoint 2 Substation	Midpoint Connection (if any)	Operating Voltage (kV)	Est. Cost (Millions)	Expected Construction Start Date	Expected In-Service Date	New ROW Required	Substation Modifi-cations Required	PSCW Status and Docket Number
ATC Transmission Lines									
Arrowhead	Gardner Park (Weston)	Stone Lake	345	$429.0	Under Construction	Jun-08	No	Yes	Approved 05-CE-113
Hiawatha	Indian Lake		138	$49.6	Under Construction	Jun-09	No	Yes	Michigan Project
Columbia	North Madison		345	$30.6	Under Construction	Jun-06	No	Yes	Approved 137-CE-119
Morgan	Stiles	Falls, Pioneer	138	$9.0	Nov-04	Dec-05	No	No	Approved 137-CE-130
Plains	Stiles	Amberg	138	$98.5	Dec-04	Jun-06	No	No	Approved 137-CE-124
Martin Road	South Fond du Lac/ Ohmstead		138	$1.6	Jul-05	Jun-06	No	Yes	
North Beaver Dam	East Beaver Dam		138	$2.3	Jan-06	Jun-06	No	Yes	137-CE-131
Turtle	Bristol		69	$5.9	Jan-06	Jun-06	No	Yes	Approved 137-CE-128
Southwest Delavan	Bristol		69	$7.7	Apr-06	Jun-07	No	Yes	137-CE-136
Sycamore	Sprecher	Reiner	138	$5.9	Apr-06	Mar-07	No	Yes	Approved as part of 137-CE-120
Sprecher	Femrite		138	$22.0	May-06	Feb-07	No	Yes	Approved 137-CE-120
Cranberry	Conover		115	$17.1	Oct-06	Dec-09	Yes	Yes	137-CE-125
Jefferson	Stony Brook	Lake Mills	138	$21.9	Oct-06	Jun-07	No	Yes	137-CE-121
Kegonsa	Femrite	McFarland	138	$3.4	Oct-06	Feb-07	No	Yes	

Endpoint 1 Substation	Endpoint 2 Substation	Midpoint Connection (if any)	Operating Voltage (kV)	Est. Cost (Millions)	Expected Construction Start Date	Expected In-Service Date	New ROW Required	Substation Modifi-cations Required	PSCW Status and Docket Number
Plymouth #4	Forest Junction/ Howards Grove		138	$2.5	Nov-06	May-07	Yes	Yes	
Venus	Metonga		115	$8.7	Dec-06	Jun-07	No	Yes	137-CE-126
Gardner Park	Central Wisconsin		345	$97.2	Jan-07	Jan-09	No	New Substation	137-CE-122
Canal	Dunn Road		138	$6.4	Feb-07	Jun-08	No	Yes	137-CE-140
West Darien	Southwest Delavan		69	$5.8	Apr-07	Jun-06	No	Yes	Approved 137-CE-117
Hiawatha	Mackinac (Straits)	Pine River	138	$73.2	May-07	Jul-09	No	Yes	Michigan Project
Gardner Park	Hilltop		115	$7.3	Jun-07	Dec-07	No	Yes	137-CE-135
Rock River	Elkhorn	Bristol	138	$5.1	Aug-07	Jun-08	No	Yes	
Rockdale	West Middleton		345	$61.0	Sep-07	Jun-11	Yes	Yes	
Morgan	Werner West		345	$117.9	Oct-07	Dec-09	No	No	137-CE-123
Conover	Plains		138	$99.3	Jan-08	Aug-08	No	Yes	137-CE-125
North Madison	Waunakee		138	$11.1	Jan-08	Jun-08	Yes	Yes	137-CE-139
Pulliam	New Suamico		138	$12.9	Jan-08	Jun-08	No	Yes	
Rubicon	Horicon	Hustisford	138	$16.0	Jan-08	Jun-08	Yes	Yes	137-CE-138
Montrose	Oak Ridge	Sun Valley	138	$6.5	Apr-08	Oct-08	Yes	Yes	
Hillman	Eden		138	$20.4	Aug-08	Jun-10	No	Yes	
Waunakee	Blount		138	$20.0	Oct-09	Jun-10	No	Yes	
Salem**	West Middleton	Spring Green	345/138	$297.2	Jan-11	Jun-13	Yes	Yes	
West Middleton	North Madison		345	$46.7	Jul-12	Jun-14	Yes	No	
NSPW Transmission Lines									
Border	Chisago County	St. Croix Falls	161	$15.2	Jul-05	Dec-05	No	Yes	
Dairyland Power Cooperative Transmission Lines									
Apple River	Chisago, MN	Lawrence Creek, MN	161/115	$11.6	Jul-08	Dec-10	No	Yes	Approved 1515-CE-102 4220-CE-155
**This is a representative ATC access project. ATC has not determined which access project would likely be filed									

Table A-03 Proposed and Approved High-Voltage Transmission Line Additions Involving New Rights-of-Way

Project	Voltage (kV)	New ROW Length (mi)	Screening Area[1] (sq mi)	Corridor Sharing Opportunities	Public Lands	Sensitive Resources	Cultural Resources[2]	Miscellaneous
Cranberry-Conover	115	11	74	State highways 32/45, 17, county highways, local roads, existing transmission and distribution lines, and railroad corridors	Chequamegon/Nicolet National Forest, Northern Highland - American Legion State Forest, Eagle Lake Park	Numerous lakes, streams, wetlands, and forested lands	High potential for historic and cultural resources	Eagle River Union Airport
Plymouth #4 - Forest Junction/ Howards Grove	138	1.2	2.5	State highways 23 and 57	None	Sheboygan River, Mullet River, Otter Creek, scattered wetlands, some forested lands	None	
Rockdale-West Middleton	345	28	290	New ROW will be required. State and county roads and existing transmission ROWs	Numerous city, county, and state parks including Indian Lake, LaFollette, and Festbe County Parks, Governor Nelson, and Lake Kegonsa State Parks, portions of the Glacial Drumlin State Trail, and several state fishery and wildlife areas	Bean Lake, Red Cedar Lake, and the Hook Lake/Grass Lake state natural areas, and much of the Yahara River drainage basin	The Koshkonong Norwegian Settlement, Bernard-Hoover Boar House, Robert M. LaFollyette House, Gilmore House, Olin House, the State Capital, several effigy mound sites, numerous museums, and the Langdon Street, Sherman Avenue, Third Lake Ridge, and Universi	
North Madison-Waunakee	138	5	47	State Highway 113 and other county highways, and local roads	None	Sixmile Creek, Empire Prairie State Natural Area, and various tributaries, isolated wetlands and woodlots	None	
Rubicon-Hustisford	138	5	45	State highways 60 and 67, county highways EE and N	None	Lake Sinissippi, Neosho Millpond, Rubicon River, Hepp Creek, and scattered wetlands and woodlots	None	
Montrose-Sun Valley-Oak Ridge	138	9	63	County and local roads, and a recreational trail	Nevin Hatchery, Brooklyn Wildlife Area, and a WDNR recreational trail are located within the screening area.	The Sugar River and associated wetlands, Story Creek, and other unnamed streams and wetlands	Architectural and historic sites	Moderate probability of encountering endangered resources.
Salem-Spring Green-West Middleton	345	114	2480	Numerous highways and local roads, existing transmission ROWs, and railroad corridors	Nelson Dewey State Park, Governor Dodge State Park, Tower Hill State Park, Bluemounds State Park, Blackhawk Lake Recreational Area, Turkey River Mounds State Park (IA), White Pine Hollow State Forest Preserve (IA), Lower Wisconsin State Riverway, numero	Upper Mississippi River National Wildlife and Fish Refuge, Lower Wisconsin State Riverway, numerous Wisconsin State Natural Areas, several State Preserves and recreational areas, the Mississippi and Wisconsin Rivers and their tributaries, and various othe	High potential for encountering cultural and historic resources	

Project	Voltage (kV)	New ROW Length (mi)	Screening Area[1] (sq mi)	Corridor Sharing Opportunities	Public Lands	Sensitive Resources	Cultural Resources[2]	Miscellaneous
West Middleton-North Madison	345	20	42	State highways 12, 14, 113, and 19, county highways and electrical distribution ROWs	Lodi Marsh wildlife area, county and local parks.	Pheasant Branch, Black Earth Creek, Halfway Prairie Creek, Sixmile Creek, tributaries to the Yahara River, Brandenburg Lake, Lodi Marsh State Natural Area.	None	Morey Airport

1 - Screening Area Width is defined as follows:
For lines 0 to 5 miles long, the screening area width equal length of segment;
For lines 5 to 15 miles long, the screening area width equals 5 miles;
For lines greater than 15 miles, screening area width equals 30 percent of line length.

2 - Cultural Resources are those resources listed on the statewide cultural resource map.

APPENDIX B

Topical Questions to Aid Commission Policy Direction

1. What are the three most important policy challenges facing the Commission, and how should the Commission address such challenges?

Responses of Consumer and Industrial Advocacy Groups

- Need for new infrastructure
- Interaction with regional markets
- Mergers
- MISO Day 2 Market
- Scenario planning
- Utility rate certainty

Responses of Utility Providers

- Review of generation and transmission projects
- Customer access to a diverse electric energy mix
- Ensuring the right projects are undertaken at the right time
- Transmission
- Risk management
- Fuel rules
- The rapidly changing market and regulatory environment
- Flexibility in policy determination
- Investment in the energy infrastructure
- Regulatory certainty
- Environmental, renewable and demand side management
- Communications with the public
- Financial stability, associated risk with innovative technologies and possible financial incentives
- Import capability
- Reserve requirements
- Moderation of rate increases
- Implementation of the Energy Policy Act of 2005
- MISO market
- Management of the state's generation portfolio
- Transmission construction and flexibility regarding localized needs

2. Given the construction program that will occur over the next seven years, what are your ideas on the best ways for the Commission to mitigate the upward pressure on electricity rates?

Most comments on this issue acknowledge the reality of being in an environment where utility rates are increasing. The Commission received comments from not only utility service providers, but other interested participants as well. In summary:

Responses of Consumer and Industrial Advocacy Groups

- Increase the delivery of energy efficiency services.
- Authorize demand response programs, including progressive rate designs.
- Authorize distributed generation options.

- Control fuel costs.
- Withdraw Wisconsin utilities from MISO participation if the Commission cannot protect ratepayers from higher costs, compared to not participating.
- Protection from diversification of utility holding companies into unregulated business ventures.
- Strengthen the energy planning process.
- Shorten regulatory review time.

Responses of Utility Service Providers

- Reconsider the PSC's interpretation of the Energy Priorities Law.
- Delivery of energy efficiency and renewable programs should stand on their own merits.
- Consider pricing policies that provide proper price signals, without cross-subsidies.
- Streamline the regulatory process.
- Allow planned incremental rate-base additions to be recovered in rates to mitigate rate shock.
- Reduce the amount of investment put into rate base by reducing the Allowance Funds Used During Construction (AFUDC).
- Improve access to other markets (Access Study Initiative).
- Eliminate the requirement for alternative generation sites for facilities proposed at existing generation sites.
- Strict adherence to cost of service regulatory principles.
- Use innovative financing measures.
- Improve the electric planning process.
- Reduce excessive rates of return on equity.

3. In the last SEA, many participants indicated a need for improved generation and transmission planning, but there was a shortage of specifics. Please identify specifically how such integration should occur, taking note of MISO market developments.

Responses from Consumer and Industrial Advocacy Groups

- The joint comments of CUB, Clean Wisconsin and RENEW Wisconsin strongly state the "need for a broader, integrated, strategic public planning process that recognizes the changes that have and are occurring in the industry…" They see an expanded SEA process with periodic legislative style hearings with public interaction to test others' assessments, while identifying the risks and opportunities.
- The response of WIEG, WMC, and WPC endorses fundamental scenario planning along with the close examination of the MISO Day 2 environment with focus on the cost-benefits studies of the MISO market.

Responses from Utility Providers

- Expand the horizon of the plans beyond the current seven years.
- Expand beyond one state's footprint and transmission system.
- Use the Locational Marginal Pricing mechanism with the information for energy and congestion components as signals for generation and/or transmission.

- Use MISO's MTEP process including the exploratory studies, reliability studies and economic benefit studies in MTEP06.
- Effort needs to be broad and flexible with a very dynamic market.
- Public availability of the information with all the market participants is key.

General Comments from Most Participants

- On an infrequent basis perform some exploratory plans out to 20 years for a range of generation scenarios to develop a backbone EHV system.
- Have multiple generation site interconnection studies.
- Have long term financial transmission rights.
- Review in detail the generation to market deliverability test, the transmission service request and the amount of transmission for "capacity."
- Consistent transmission pricing allocations.
- A common resource adequacy requirement for MISO.
- Consistent MISO transmission planning practices.
- Avoidance of detailed and rigid rules for a very dynamic market.
- Have the PSC involved with the OMS and MISO developments.
- Encourage the development of generation sites with joint partners to minimize costs and transmission additions.

It was pointed out there are conflicts with the concept of joint, determination-style planning in today's market, while maintaining the confidentiality of the different market participants. One example is the potential exposure of Wisconsin's regulated utilities' detailed strategic fuel plans, with no ability to require or have the same information from utilities in the surrounding states or from non-regulated entities like IPPs. This can put the regulated entity at a competitive market disadvantage and at risk for additional costs. One solution is to avoid site specific generation expansion scenarios, but use sub-regional injection locations and broad load sink areas.

4. Please identify and quantify the benefits and costs that Wisconsin ratepayers have seen from MISO's wholesale power market and are likely to see over the period covered by the SEA.

All respondents indicated that it was very difficult, or not possible to quantify the costs and benefits of the MISO market. At the time of the responses the MISO market was less than six months old. The responses indicated that utilities experiences were very different with certain aspects of the MISO market, so their comments are listed by utility name.

Responses of Consumer and Industrial Advocacy Groups

- Acknowledged the difficulty in collecting data that are necessary to assess the overall costs and benefits of MISO and Day 2 but they strongly supported having MISO undertake an independent, appropriately designed benefit/cost assessment of MISO.

- A real benefit to Wisconsin ratepayers is critical to a decision to remain in MISO.

- Consumer groups believe Wisconsin ratepayers may be paying more for electricity with an LMP market than they would in the absence of such a market.
- A performance metric to assure Wisconsin utilities are serving native load in a least cost manner and to determine if MISO's LMP market is successful in implementing a least-cost economic dispatch should be constructed.
- Urges the Commission to aggressively scrutinize costs and revenues associated with the utilities' obligation to fulfill native load requirements.
- MISO may not be able to serve the Wisconsin utility needs in a least cost manner to fulfill obligations of the state's renewable portfolio standard.

Responses of Utility Providers

- DPC felt that energy prices had gone up and that congestion management was poorer with MISO compared to the pre-MISO Day 2 Market world.
- NSPW felt that energy prices were going to be lower with a centrally dispatched system compared to bilateral contracts. NSPW also believed that congestion management was better under MISO than it was prior to MISO.
- MGE noticed "occasions" where MISO's system of dispatch appeared to have been beneficial, especially when not all of MGE's generation resources were available.
- WEPCO noticed improved transmission efficiency and improved dispatch efficiency.
- WPSC noted that MISO did a very good job minimizing the impact of a forced outage of the Eau Claire-Arpin 345 KV transmission line.
- WP&L expects that energy pricing and transmission utilization will improve, but noted it was too early to see if the expected benefits had been obtained. WP&L believed it may take a full year of operation to work through the complexity of MISO's Day 2 Market for both operations and accounting issues to be resolved.

General Responses

- Virtually all respondents had significant concerns about the administrative costs associated with MISO and with the financial settlement process. MISO has had significant uplift charges due to revenue insufficiency. MISO operates the system and imposes a tariff to cover its administrative costs. However, if the dollars paid out to generators are greater than the charges collected from power purchasers, MISO passes the costs along to all participants. The billing process had resulted in significant revenue shortages for MISO. This resulted in additional uplift charges passed along to all market participants. MISO has made several changes in their billing processes but it will take several more months to see if this has been resolved.

5. Does your utility anticipate that the EPA's changes in environmental regulations regarding SO_2, NO_x and mercury will affect fuel choice, output, and operating costs of your utility's generating units and your utility's cost of service? If so, please document and describe the changes that are expected to occur, and quantify the expected impacts on fuel choice, output and operating costs. Also, how does your utility expect to use the purchase or sale of emission allowances to minimize risk and minimize costs to comply with new EPA environmental regulations?

Responses from Consumer and Advocacy Groups

None.

Responses from Utility Providers

- New regulations will require installation of control equipment which will increase the costs associated with generation.
- Operating costs will increase due to increased fuel costs, use of chemicals, labor costs associated with waste removal.
- Output of generating units will be impacted due to increased house load requirements.
- Fuel choice will be impacted.
- Energy output will be affected.
- Will need flexibility in generation planning.
- Favors market based solutions.
- Possibility of wide-scale retirements of existing generation facilities across the country.
- The CAIR and the CAMR will likely increase cost of service and operating costs.
- Participation in the Metro Emission Reduction Program could mitigate some of the increases.
- A robust emissions credit market is critical.
- Foresees fuel switching.
- The fact that the CAIR is being litigated complicates planning.

6. Congress is considering adopting a Federal Energy Bill. What impacts to Wisconsin utilities, shareholders, and ratepayers do you foresee from its adoption? Be sure to cover the list of potential titles/policy changes as known on September 1, 2005, or the actual titles/policy changes if enacted into law this summer.

This question was asked prior to promulgation of the Energy Policy Act of 2005 (EPAct 2005). Responses were received after the passage of EPAct 2005.

Responses of Consumer and Industrial Advocacy Groups

- Several of the requirements in the EPAct 2005 present an opportunity for the development of rate designs and demand response programs that can help Wisconsin ratepayers save energy and money.
- Demand response and real time pricing requirements in the Act have the potential, when properly administered, to create energy and monetary savings.
- Changes to the Public Utility Regulatory Policy Act of 1978 (PURPA) may have unintended consequences for industrial customers that own small

Qualifying Facility generators. Incentives to develop long term FTRs will have a positive benefit on the market for energy.

Responses of Utility Providers

The responses from utility providers are summarized by the EPAct 2005 titles and the respondent's comments are noted. Some respondents listed the provisions that they felt were significant while others respondents provided specific comments on how those impacts would affect Wisconsin.

TITLE 1: Energy Efficiency

- Federal buildings are required to reduce their energy use. WP&L noted that the provision to require federal buildings to reduce energy usage may provide opportunities for WP&L's Shared Savings program to partner with federal agencies to meet these requirements.
- Daylight savings time is extended. Daylight savings time adjustments may require system and meter updating that may have costs for utilities noted WP&L.
- Funding for federal energy assistance programs including the Low Income Home Energy Assistance Program (LIHEAP), the Federal Weatherization Assistance Program, and other grants and incentives are increased in EPAct 2005. WP&L notes that this may create opportunities for Focus on Energy. WPSC notes that while LIHEAP appropriations have been increase, the formulae for calculation will also change and Wisconsin should monitor these changes as they affect our residents.
- Energy efficiency programs that affect ratepayers including heating/ventilating/air conditioning (HVAC) maintenance education may reduce the need to use the State's Focus on Energy funds on these efforts freeing up funds for other uses. WP&L notes that efforts to promote energy efficiency programs may create opportunities for its Shared Savings program.
- WP&L notes that provisions to address energy efficiency in public housing may reduce uncollectible accounts and reduce the costs of uncollectible accounts that are passed through in rates.

TITLE XIII: Electricity

- Jurisdiction for reliability is transferred to FERC which is ordered to promulgate and enforce reliability standards.
- There may be some costs incurred in a mandatory reliability standard but the benefits from avoided blackouts, such as the August, 2003 northeastern blackout, are likely to far outweigh these costs.
- Concerned that some utilities may try to water down reliability rules.
- Additional personal and training are likely to be needed to meet new, enforceable reliability standards.

- The DOE is required to conduct a study of transmission system modernization. FERC is given backstop siting authority for transmission lines in corridors identified by the DOE as having national significance. EPAct 2005 allows the creation of regional siting authority by compact between three or more contiguous states. If states are unwilling or unable to approve a transmission project, FERC may do so. WP&L believes that to the extent that projects have not been sited in other states this may provide relief to Wisconsin ratepayers as it will allow needed infrastructure development. DPC believes these provisions may result in better cooperation among states affected by interstate transmission construction projects and may result in more and better transmission construction projects. WP&L believes that multi-state compacts may be beneficial.
- Provisions are created to protect existing transmission rights and FERC is directed to take steps to make long-term transmission rights available for new resources. WPPI, MGE, DPC, and WP&L find this to be critically important.
- PURPA is modified to require state regulatory agencies to determine if they need to adopt new standards for net metering, fuel diversity, and fossil fuel generation efficiency. WP&L believes that the PSC has addressed these issues in Wisconsin. States are also required to determine if they need to adopt time-based metering and communications. WP&L notes that many residential customers currently participate in time of use rates but questions whether residential customers would embrace hour by hour energy management although some commercial and industrial customers may find this worth the effort and cost. WPSC notes that added investment requirement on the part of utilities for compliance may have ratepayer impacts.
- PURPA is modified to remove the new facilities mandatory purchase requirement on utilities if the utilities are in areas with independently administered auction-based day ahead and real time wholesale electricity markets. MISO Day 2 meets this definition. WP&L believes this will be a benefit to Wisconsin ratepayers by avoiding utilities from paying above market rates for electricity.
- The Public Utility Holding Company Act (PUHCA) is repealed. WPSC believes that this may remove certain restrictions now in place that limit capital investment. WP&L believes that this will be an indirect benefit to Wisconsin ratepayers through improved national reliability and a more robust wholesale market. WP&L believes this will be a benefit to shareholders on a national basis. DPC believes the repeal of PUHCA means that state laws regarding utility merges and acquisitions need to be as strong as possible to protect consumers. DPC strongly supports the Wisconsin holding company act's provisions for dealing with utility mergers and acquisitions. MGE believes that Wisconsin's holding company law will mute effects within this state, but remains concerned about rising market power within MISO and PJM if there are a lot of mergers. WPPI regrets that PUHCA is repealed. WEPCO notes that investors that had not traditionally owned utilities may now be encouraged to do so.
- FERC is required to convene joint boards on a regional basis to study the economic and reliability impacts of security constrained economic dispatch, such as that done by MISO in Day 2. The joint boards, through FERC, are to

report to Congress on their findings. WP&L believes that the FERC report may be very important to Wisconsin as it may affect the operations of MISO.

TITLE XVI: Climate Change

- This title establishes a committee on technology and creates a strategy to promote the deployment and commercialization of greenhouse gas intensity reduction technologies. This title also creates terms and conditions under which the DOE Secretary will make loan guarantees for projects that either reduce, avoid, or sequester greenhouse gasses including IGCC electric generation.
- WP&L believes that Wisconsin may not be in position economically or from a reliability perspective to serve as a testing ground for projects that can use these loan guarantees, but that development and commercialization of these technologies may provide long term benefits to Wisconsin consumers.

TITLE XVIII: Tax Incentives

- New transmission lines greater than 69 kV now are allowed to be depreciated over 15 years, rather than 20 years.
- A tax credit for new, advanced nuclear power facilities, limited to 6,000 MW of capacity and placed into service prior to 2021, is established.
- Clean coal facilities, IGCC and other, are eligible for tax credits but the total amount of tax credits the DOE Secretary may allocate are $800 million for IGCC projects and $500 million for other advanced coal technologies.
- A seven year amortization period for certain air pollution control facilities place into service on or after April 11, 2005, and the requirement that the underlying facility have been constructed and in service prior to January 1, 1976, is repealed.
- The renewable energy production tax credit is extended for two years. A new category of tax exempt renewable energy bonds is created. Fuel cell and micro turbine business energy credits are established.
- A series of tax incentives for energy efficiency and conservation for projects with investments made between January 1, 2006, and December 31, 2007, are established.
- Natural gas distribution line depreciation is reduced to 15 years from 20.
- Nuclear decommissioning trusts fund rules are modified repealing the cost of service requirement for contributions to a qualified fund and allowing the transfer of pre-1984 funds from non-tax qualified accounts to tax qualified accounts.
- MGE believes that the two-year extension on wind power is a mixed blessing. MGE supports the credit, but a longer extension would foster better planning and smooth the construction boom and bust that is fostered by uncertainty in the tax credit's horizon.

7. Should the Commission support pipeline capacity additions that may not be economically feasible for individual natural gas utilities if there are significant non-economic benefits for the state of Wisconsin? If so, please comment on the non-economic benefits (non-economic from the individual gas utility's ratepayer's perspective) and how they might be considered. If not, explain why you believe our pipeline expansion criteria should be focused solely on gas utility system sales ratepayers.

Responses from Consumer and Advocacy Groups

- Avoid creating competition for pipeline space between space and water heating and industrial uses, with natural gas needs for electric generation.
- Ensure proper cost allocation to those entities causing the costs and receiving the benefits.
- Non-economic expansion should not be considered due to upward pressure on rate.

Responses from Utility Providers

- Economic and non-economic benefits should be considered.
- Competitive advantages with other pipelines should be considered.
- Proper cost allocation in rate design should be made.
- Flexibility in the regulatory treatment is key.
- Ratepayers should pay for only the additional pipeline capacity from which they benefit.
- Review should be on a case-by-case basis.